# Technical Support Document
# Federal Implementation Plan for Existing Oil and Natural Gas Sources; Uintah and Ouray Indian Reservation in Utah
# Docket Number: EPA-R08-OAR-2015-0709
# FRL-XXXX-X
# SAN#: 5872

## I. Introduction

The Environmental Protection Agency (EPA) is proposing to promulgate a Federal Implementation Plan (FIP) under the Clean Air Act (CAA) specific to the Indian country lands within the Uintah and Ouray Indian Reservation (U&O Reservation). In this FIP, the EPA proposes to establish federally enforceable requirements to control volatile organic compound (VOC) emissions from existing sources in the production and natural gas processing segments of the oil and natural gas sector that are located on Indian country lands within the U&O Reservation in Utah, within the Uinta Basin.

Through the FIP, we[1] propose to require owners and operators of affected existing oil and natural gas sources[2] to reduce the VOC released during the production (and storage, which is part of production) of hydrocarbon reservoir fluids prior to being transferred off site for sale or treatment, and during natural gas processing. This rule, if finalized, will be implemented by us (or by the Ute Indian Tribe, if delegated the authority to do so) until replaced by an EPA-approved Tribal Implementation Plan (TIP).

This proposed rule, if finalized, will be an important step toward providing public health and welfare protection on the Indian country lands within the U&O Reservation by improving ozone air quality. At the same time, this FIP will allow for continued environmentally responsible development of the U&O Reservation's oil and natural gas resources, which provide significant economic benefits to the Tribal community through royalties and employment opportunities. This proposed FIP also will provide regulatory certainty to owners and operators through VOC emission control requirements that are consistent with requirements imposed on such existing non-Indian country sources within and surrounding the U&O Reservation that are regulated by the Utah Department of Environmental Quality Division of Air Quality (UDEQ). We analyzed data provided by the oil and natural gas industry submitted to the EPA under the registration requirements of the Federal Minor New Source Review Program in Indian Country at 40 CFR Part 49 (Federal Indian Country Minor NSR Program or Rule)[3]. We identified the primary oil and natural gas -related sources of air pollution emissions on the Indian country lands within the U&O Reservation. We also evaluated the CAA statutory authorities available to regulate these existing sources. Our research and analysis has identified significant VOC emissions at existing oil and natural gas sources on the Indian country lands within the U&O Reservation that are

[1] Throughout this document, "we" "us" and "our" refer to the EPA.
[2] As defined in the proposed rule.
[3] Review of New Sources and Modifications in Indian Country, Published in the Federal Register on July 1, 2011 (76 FR 38748), available online at http://www.gpo.gov/fdsys/pkg/FR-2011-07-01/pdf/2011-14981.pdf, accessed October 14, 2015. The existing source registration program requirements are specified at 40 CFR 49.160, with registration forms available online at http://www3.epa.gov/air/tribal/tribalnsr.html, accessed December 2, 2015.

often not subject to any emissions control requirements. Our analysis identified a regulatory patchwork of inconsistent VOC emissions control requirements across tribal and state jurisdictions in, and surrounding, the Uinta Basin.

## II. Description of the Equipment on the U&O Reservation that EPA Proposes to Control

In this FIP, the EPA is proposing that owners and operators of existing oil and natural gas sources on the Indian country lands within the U&O Reservation in the Uinta Basin[4] reduce emissions of VOC from:

- Crude oil, condensate, and produced water storage tanks;
- Glycol dehydrators;
- Pneumatic pumps and pneumatic controllers;
- Fugitive emissions components; and
- Tanker truck loading and unloading.

This rule does not contain proposed requirements for, nor will it otherwise apply to, the following other types of equipment that may be present at existing oil and natural gas sources and emit VOC:

- Compressors,
- Evaporation ponds,
- Two and three-phase separators,
- Heater treaters,
- Liquids unloading,
- Turbines, and
- Reciprocating internal combustion engines.

This proposed rule also will not apply to new or modified oil and natural gas sources that commence construction after the effective date of the final rule. New and modified oil and natural gas sources are expected to be regulated under the New Source Performance Standards (NSPS) for the Oil and Natural Gas Sector at 40 CFR Part 60, subpart OOOO (NSPS OOOO), and subpart OOOOa (NSPS OOOOa).[5] The EPA also expects to control emissions from new and modified oil and natural gas sources under the

[4] EPA's Greenhouse Gas Reporting Program – Subpart W, covering the Petroleum and Natural Gas Systems, defines the Uinta Basin as the counties of Carbon, Daggett, Duchesne, Uintah and Wasatch. The Western Regional Air Partnership (WRAP) defines the Uinta Basin as wholly including the counties of Carbon, Duchesne, Emery, Grand, Uintah, and Wasatch, see "Final Report - DEVELOPMENT OF 2012 OIL AND GAS EMISSIONS PROJECTIONS FOR THE UINTA BASIN," March 25, 2009, available online at http://www.wrapair.org/forums/ogwg/documents/2009-03_12_Projection_Emissions_Uinta_Basin_Technical_Memo_03-25.pdf, accessed October 15, 2015. For the purposes of this rulemaking, the EPA defines the Uinta Basin consistent with the WRAP's definition and analysis. Therefore, throughout this document Uinta Basin = Carbon, Duchesne, Emery, Grand, Uintah, and Wasatch Counties.

[5] NSPS OOOO was originally published in the Federal Register on August 16, 2012 at 77 FR 49490, with revisions on September 23, 2013, July 17, 2014, December 31, 2014, and July 31, 2015. Additional revisions, including the addition of subpart OOOOa, were proposed in the Federal Register on September 18, 2015 at 80 FR 56593 and were signed final by the Administrator on April 28, 2016. Information on these rulemakings is available online at http://www3.epa.gov/airquality/oilandgas/actions.html, accessed April 28, 2015.

Prevention of Significant Deterioration (PSD) preconstruction permit program at 40 CFR Part 52, the Federal Indian Country Minor NSR Program and the supplemental Federal Implementation Plan for True Minor Sources in Indian Country in the Oil and Natural Gas Production and Natural Gas Processing Segments of the Oil and Natural Gas Sector (Indian Country Oil and Natural Gas True Minor Source FIP)[6].

## III. Development of Rule

### 1. Analysis of Purpose and Need for Rule:

The proposed FIP is an important action the Agency is taking to control VOC emissions from existing oil and natural gas operations in the Indian country lands within the U&O Reservation. VOC, in concert with nitrogen oxides ($NO_X$), chemically reacts in the presence of sunlight to form ground level ozone. The requirements in this FIP are intended to address the primary concern of compromised air quality in the Uinta Basin and the secondary concern of inconsistent regulatory requirements across Indian country and State of Utah jurisdictions.

a. Current Air Quality in the Uinta Basin

With respect to air quality, ozone levels in the Uinta Basin, the region in which the Indian country lands within the U&O Reservation are located, has reached unhealthy levels that warrant action. Higher ozone levels in the Uinta Basin are a problem during the wintertime when temperature inversions and widespread snow cover on the ground occur, both of which contribute to ozone formation. The current NAAQS for ozone is 70 parts per billion (ppb).[7] Compliance with the NAAQS is determined by comparison to a "design value" that is calculated based on a three year average of the fourth highest daily maximum 8-hour average ozone measured in a year at each monitoring site. Based on the 2012 to 2014 regulatory air quality monitoring data, the 2014 ozone design values exceed the ozone NAAQS at three monitoring sites in the Uinta Basin. The current maximum regulatory three-year design value (2012-2014) is 78 ppb at the Roosevelt monitor. Based on preliminary 2015 monitoring data, five monitoring sites in the Uinta Basin are estimated to exceed the ozone NAAQS[8]. Additionally, higher ozone concentrations were observed at some sites before they were designated as regulatory monitors. For example, 8-hour average ozone concentrations reached values as high as 141 ppb at the Ouray monitor in March 2013. This concentration corresponds to an Air Quality Index value of 211, which is characterized as "Very Unhealthy."

b. Sources of Ozone-Related Emissions in the Uinta Basin

[6] "Federal Implementation Plan for True Minor Sources in Indian Country in the Oil and Natural Gas Production and Natural Gas Processing Segments of the Oil and Natural Gas Sector; Amendments to the Federal Minor New Source Review Program in Indian Country to Address Requirements for True Minor Sources in the Oil and Natural Gas Sector," Final Rule, U.S. Environmental Protection Agency, Signed April 28, 2016 and available online at https://www.epa.gov/tribal-minor-new-source-review, accessed April 14, 2016.

[7] Revised Ozone NAAQS was signed by EPA Administrator Gina McCarthy on October 1, 2015, available online at http://www.regulations.gov, Docket No. EPA-HQ-OAR-2008-0699 accessed December 2, 2015.

[8] Regulatory ozone data is available online at http://www3.epa.gov/airtrends/values.html, accessed December 2, 2015.

According to an oil and gas industry emissions inventory study by the Western Regional Air Partnership (WRAP),[9] a significant portion of 2012 VOC and $NO_X$ emissions in Duchesne and Uintah Counties were projected to occur on the Indian country lands within the U&O Reservation, and those emissions represent the majority of emissions in the Uinta Basin as a whole (see Table 1). Approximately 98 percent of VOC and 68 percent of $NO_X$ emissions released on Indian country lands within the U&O Reservation are from existing unpermitted minor oil and natural gas sources (see Table 2), and 70 percent of the wells in the Uinta Basin are on Indian country lands within the U&O Reservation (see Table 3). 76 percent of the wells on Indian country lands within the U&O Reservation began production prior to August 23, 2011, the effective date of NSPS OOOO. Figures 1 and 2 show the distribution of VOC and $NO_X$ emissions by source sector in the Uinta Basin based on the National Emissions Inventory 2011. Based on the distribution, oil and natural gas sources, the majority of which are minor sources, are, therefore, believed to be the most significant anthropogenic contributors to NAAQS exceedances in the Uinta Basin in comparison to all other industrial source types. Additionally, since the majority of existing wells on Indian country lands within the U&O Reservation began production before the effective date of NSPS OOOO, and storage vessels under that rule are only required to apply emissions controls if uncontrolled VOC emissions are greater than 6 tpy per tank, it is likely that the storage tanks associated with at least that many wells, likely some storage tanks associated with wells that began after the effective dates of NSPS OOOO and OOOOa as well, are not required to control emissions. Finally, as explained later on in this document, we believe that ozone levels in the Uinta Basin are most significantly influenced by VOC emissions from the accumulation of minor oil and natural gas production operations.

[9] Western Regional Air Partnership (WRAP), O&G Emissions Workgroup: Phase III Inventory, Uinta Basin Reports, 2012 Mid-Term Projection Technical Memo, "DEVELOPMENT OF 2012 OIL AND GAS EMISSIONS PROJECTIONS FOR THE UINTA BASIN", March 25, 2009, available online at http://www.wrapair2.org/Phase III.aspx, accessed November 30, 2015. The projections for 2012 were conducted separately for 5 geographic groupings in the Uinta Basin which are essentially 5 counties of significant oil and gas activity - Carbon, Duchesne, Emery, Grand, and Uintah. This represents the regions where significant oil and gas exploration and production are occurring. It should be noted that the boundaries of the Uinta Basin as defined in this project also include Wasatch County in the northwestern corner of the Basin, though Wasatch County does not have any significant oil and gas activity and, thus, no projections are made for this county, nor is Wasatch County included in any further analysis by the WRAP for the Uinta Basin. As a component of developing the inventory, the WRAP consulted data from the Federal Indian Country Minor NSR Program existing minor source registrations for the Indian country lands within the U&O Reservation.

Table 1 – 2012 VOC and NOx Emissions for the Oil and Gas Industry by County and by Tribal or Non-Tribal Airshed for the Uinta Basin[8]

| County | VOC (TPY) | Percent of Total | NOx (TPY) | Percent of Total |
|---|---|---|---|---|
| **Tribal Airshed** | | | | |
| Carbon | 548 | <1% | 88 | <1% |
| Duchesne | 18,613 | **15%** | 3,338 | **20%** |
| Emery | 0 | 0% | 0 | 0% |
| Grand | 301 | <1% | 371 | 2% |
| Uintah | 82,857 | **65%** | 8,622 | **52%** |
| Wasatch | 0 | 0% | 0 | 0% |
| ***Total Tribal*** | ***102,319*** | ***80%*** | ***12,419*** | ***75%*** |
| **Non-Tribal Airshed** | | | | |
| Carbon | 3,429 | 2% | 1,263 | 8% |
| Duchesne | 16,797 | 13% | 2,014 | 12% |
| Emery | 559 | <1% | 259 | 2% |
| Grand | 2,683 | 2% | 365 | 2% |
| Uintah | 1,707 | 1% | 228 | 1% |
| Wasatch | 0 | 0% | 0 | 0% |
| ***Total Non-Tribal*** | ***25,175*** | ***20%*** | ***4,128*** | ***25%*** |
| **TOTAL** | **127,495** | | **16,547** | |

Table 2 – VOC and NOx Emissions on the Indian Country Lands within the U&O Reservation[10]

| Source Type | # Sources | VOC (TPY) | Percent of Total | NOx (TPY) | Percent of Total |
|---|---|---|---|---|---|
| Existing Permitted Sources | 19 | 1,053 | 1.6% | 5,258 | 32% |
| Existing Unpermitted Minor Oil and Natural Gas Sources | 5,169 | 63,140 | 98% | 11,168 | 68% |
| Existing Minor Nonmetallic Mineral Mining Sources | 1 | 9 | 0.01% | 3 | 0.02% |
| **TOTAL** | **5,189** | **64,202** | | **16,429** | |

[10] Source: Data from existing source registration reports submitted under 40 CFR 49.160 of the Federal Indian Country Minor NSR Program by operators of sources on the Indian country lands within the U&O Reservation. Analysis of the data can be viewed in a spreadsheet in the docket for this rulemaking titled "EmissionReductionAnalysis.xlsx."

Table 3 – Number of Active Producing Oil and Natural Gas Wells in the Uinta Basin as of 12/31/14[11]

| Uinta Basin County | Total # Wells | # Wells on Indian Country Lands Within the U&O Reservation | Percent of Total Wells in Uinta Basin | # Wells on Indian Country w/ 1st Prod. <8/23/11 | Percent of Total Wells on Indian Country Lands |
|---|---|---|---|---|---|
| Carbon | 1,044 | 33 | | 15 | |
| Duchesne | 3,470 | 1,726 | | 1,005 | |
| Emery | 259 | - | | - | |
| Grand | 290 | - | | - | |
| Uintah | 7,161 | 6,628 | | 5,380 | |
| Wasatch | 1 | 1 | | 1 | |
| **TOTAL** | **12,225** | **8,388** | **69%** | **6,401**[12] | **76%** |

[11] Source: DrillingInfo available online by subscription at http://info.drillinginfo.com, accessed November 1, 2015.
[12] We are highly confident that this group of wells is not, as yet, subject to any federal emissions control requirement because they do not meet applicability criteria in our rules.

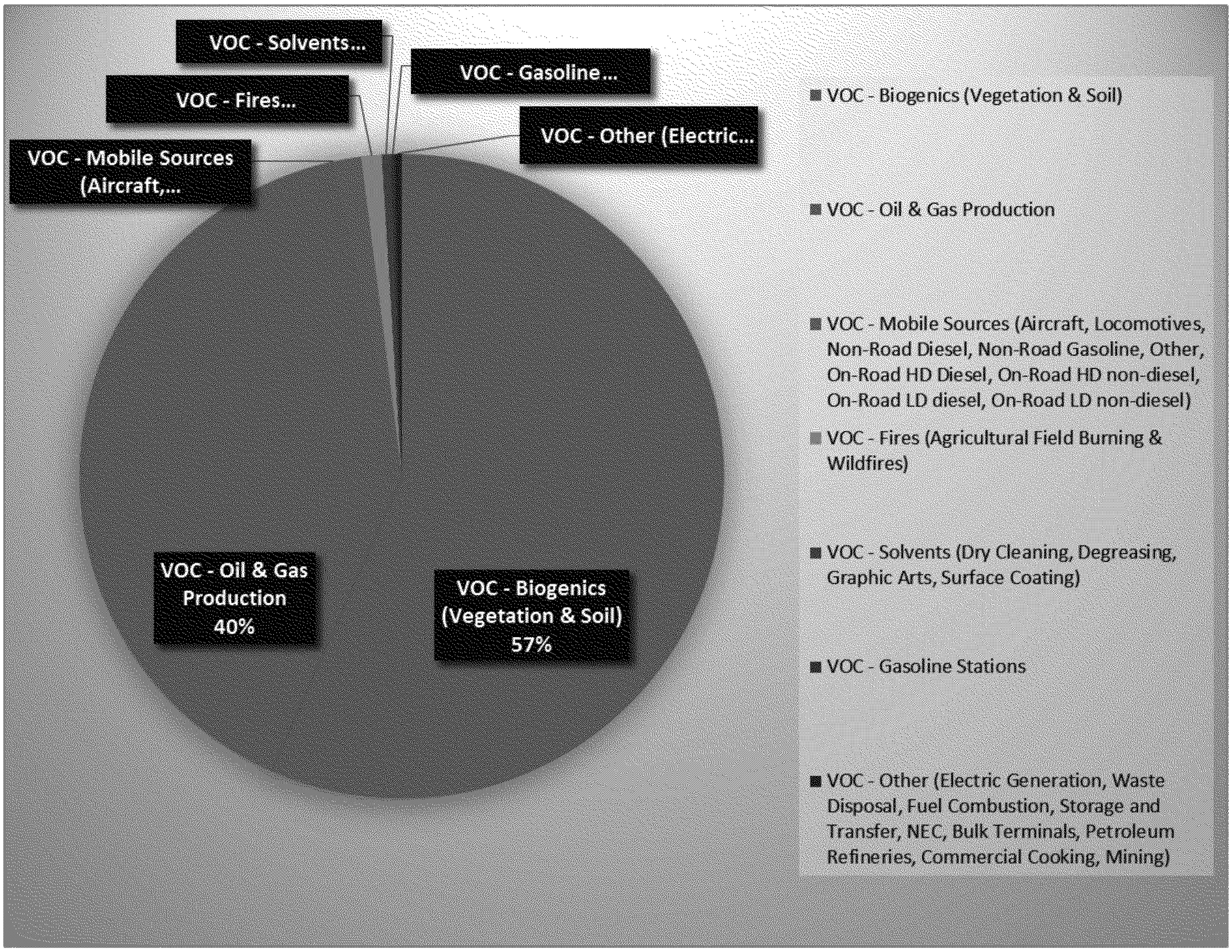


Figure 1. VOC emissions totals by source sector in the Uinta Basin based on estimates in the 2011 National Emissions Inventory.[13]

[13] Source: 2011 National Emissions Inventory, available online at http://www3.epa.gov/ttn/chief/net/2011inventory.html, accessed December 4, 2015. Analysis of the data can be viewed in a spreadsheet in the docket for this rulemaking titled "NEI_2011_All Industry VOC-NOx Uinta Basin Counties Only".

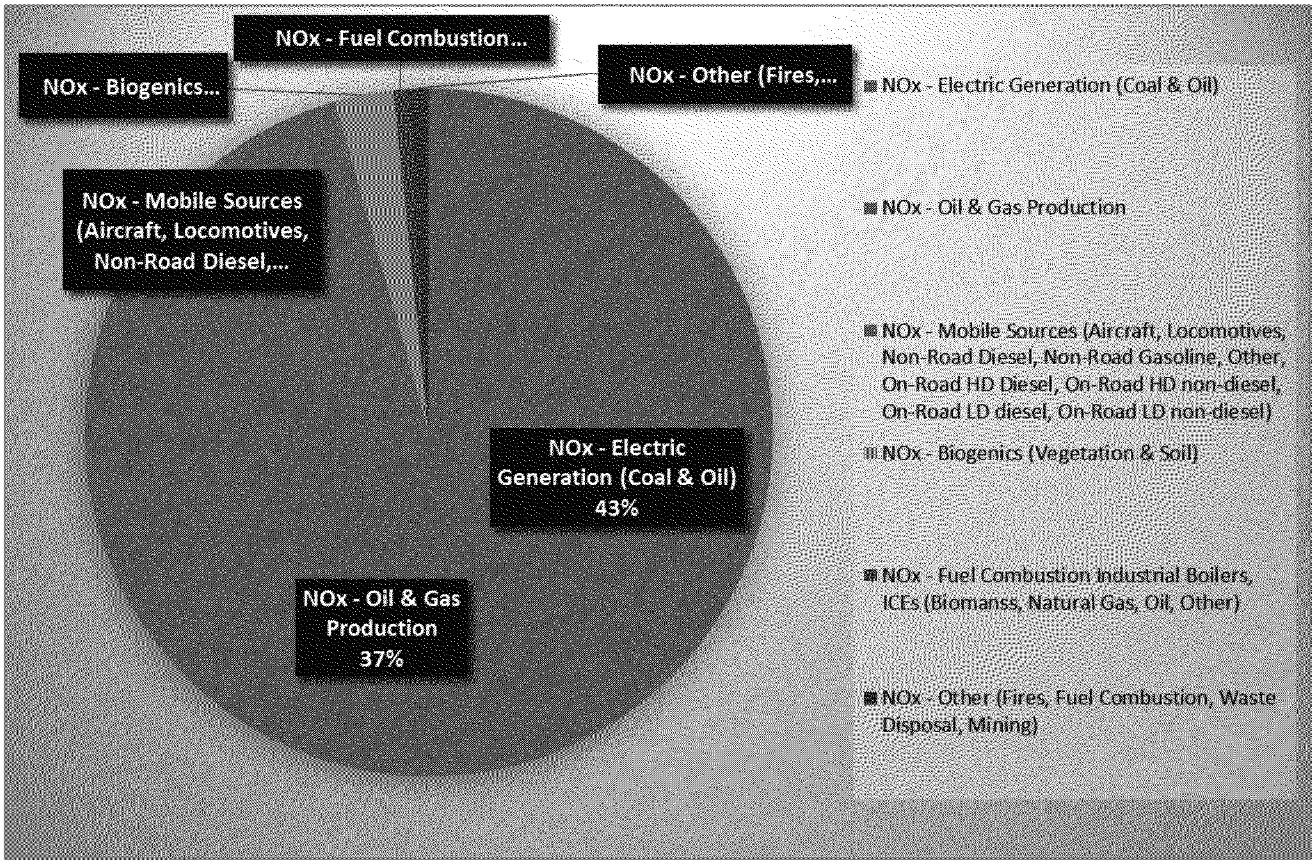


Figure 2. NOx emissions totals by source sector in the Uinta Basin based on estimates in the 2011 National Emissions Inventory.[14]

## c. Overview of Current Regulatory Requirements

With respect to regulatory requirements for oil and natural gas activity across the Uinta Basin, oil and natural gas operators currently face inconsistent regulation of VOC emissions from their activities on state-managed lands versus Indian country lands within the U&O Reservation. The majority of minor oil and natural gas sources that currently exist on the Indian country lands within the U&O Reservation are not subject to control requirements under existing EPA regulations, including NSPS OOOO, NSPS OOOOa, the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Oil and Production Facilities at 40 CFR Part 63, subpart HH (NESHAP HH)[15], and the Federal Indian Country Minor NSR Rule. On the Indian country portion of the U&O Reservation approximately 6,401 wells are

[14]Source: 2011 National Emissions Inventory, available online at http://www3.epa.gov/ttn/chief/net/2011inventory.html, accessed December 4, 2015. Analysis of the data can be viewed in a spreadsheet in the docket for this rulemaking titled "NEI_2011_All Industry VOC-NOx Uinta Basin Counties Only".

[15] National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage, originally published in the Federal Register on June 17, 1999 at 64 FR 32609, and revised on June 29, 2001 (66 FR 34548), January 3, 2007 (72 FR 26), and August 16, 2012 (77 FR 49490). Information on these rulemakings is available online at: http://www3.epa.gov/airquality/oilandgas/actions.html and http://www3.epa.gov/ttn/atw/oilgas/oilgaspg.html, accessed October 14, 2015.

largely uncontrolled (out of a total 8,338 on Indian country on within the U&O Reservation; see Table 3). On the Indian country lands within the U&O Reservation, only the NSPS OOOO, NSPS OOOOa, NESHAP HH, and certain consent decrees or agreements resulting from enforcement negotiations currently potentially provide legally and practically enforceable VOC control requirements. Further, NSPS OOOO and NSPS OOOOa only apply to new and modified sources as of a certain date and NESHAP HH does not require emission reductions on lower emitting glycol dehydrators on the Indian country lands within the rural U&O Reservation. Draft Control Techniques Guidelines (CTG) have been developed/issued for existing oil and gas sector operations. The CTG would only apply in ozone nonattainment areas designated moderate or worse and to states in the Ozone Transport Region.

Owners and operators of minor oil and natural gas sources on the Indian country lands within the U&O Reservation are potentially subject to the federal preconstruction permitting requirements found in the Federal Indian Country Minor NSR rule. The Federal Indian Country Minor NSR rule applies to any new or modified minor source (as defined at 40 CFR 49.152) that exceeds the minor source emission thresholds in the rule. An existing oil and natural gas source could become subject to the Federal Indian Country Minor NSR rule if it undergoes a modification that is above those thresholds. However, owners or operators of existing minor sources are only currently required to register with the EPA under the Federal Indian Country Minor NSR rule and are not required to obtain permits that apply emission control technologies. New and modified minor oil and gas production sources will not be required to obtain a permit until on or after the current compliance deadline of March 2, 2016.[16] The EPA analyzed emissions data submitted by the owners and operators of existing oil and natural gas sources under the registration requirements of the Federal Indian Country Minor NSR rule (herein referred to as the existing minor source registration data), which indicates that minor oil and natural gas sources are the most significant sources of VOC emissions on the Indian country lands within the U&O Reservation. Most of these existing oil and natural gas sources currently are not required to reduce their VOC emissions. Of the 5,169 minor source registrations submitted, 232 reported controls on tank emissions. Of the 1,852 glycol dehydrators reported in registrations, 12 were determined to be controlled because they were located at sources that reported tank emission control.

By contrast, oil and natural gas sources off the U&O Reservation are governed by Utah Department of Environmental Quality Division of Air Quality (UDEQ) regulations and preconstruction air pollution control permitting programs that do regulate VOC emissions. As a result of these regulations and permitting programs, owners and operators of existing oil and natural gas sources in UDEQ jurisdiction are provided mechanisms for establishing legally and practicably enforceable control requirements that reduce VOC emissions, protecting air quality and providing regulatory certainty to owners and operators of oil and natural gas sources in the Uinta Basin.

The proposed regulations in this FIP for air pollution control of existing sources is consistent with the approach being implemented in the state-managed areas surrounding Indian country lands within the U&O Reservation. Owners and operators of new and modified oil and natural gas sources in state-managed portion of the Uinta Basin are subject to the Utah's preconstruction permitting requirements

[16] The EPA has proposed to revise the March 2, 2015 compliance date to October 3, 2015. Information on the proposed revision is available online at http://www3.epa.gov/airquality/oilandgas/actions/html, accessed December 7, 2015.

(Utah Permitting Rules)[17]. The Utah Permitting Rules apply if uncontrolled actual emissions are greater than the minor source preconstruction permitting thresholds of five tons per year (tpy) for any NSR-regulated pollutant. Utah has had a minor new source review program (preconstruction permits) since November 1969. The 5 tpy threshold was implemented in 1997 to clarify which sources should be permitted. Before 1997 there was no size threshold, and any minor source could be permitted. Additionally, owners and operators of all oil and natural gas sources, regardless of emissions levels, are also subject to the Utah rules for the oil and natural gas industry (Utah Oil and Gas Rules)[18]. These regulations provide VOC emission control requirements for all existing pneumatic controllers, existing flares, tanker truck loading and unloading, and existing air pollution control equipment, regardless of source-wide emissions.

In addition to protecting public health and the environment by improving air quality on the Indian country lands within the U&O Reservation, this rule will create consistent emissions control requirements across jurisdictional boundaries. Consistent with the regulatory structure that exists for existing oil and natural gas sources off the Indian country lands within the U&O Reservation, this rule will establish VOC emissions control requirements and emissions reductions, monitoring, recordkeeping and reporting that are unambiguous and legally and practicably enforceable with regard to existing oil and natural gas production, treatment, processing, and storage operations. This rule will also provide certainty for the regulated community because requirements will be consistent across regulatory jurisdictional boundaries.

## 2. Sources of VOC Emissions from Existing Oil and Natural Gas Sources

The EPA has received more than 5,100 registrations[19] for existing minor oil and natural gas sources on the Indian country lands within the U&O Reservation since the effective date of the Federal Tribal NSR Rule. The EPA's review of these registrations indicates that the majority of the owners and operators are producing a range of reservoir products from the Uinta Basin, including crude oil, condensate, and natural gas. According to data on "actual" emissions[20] submitted to the EPA by owners and operators as part of the existing minor source registrations, oil and natural gas production minor sources emit the overwhelming majority of the ozone precursor emissions of VOC and NOx emitted on the Indian country lands within the U&O Reservation (see Table 4), which includes many of the more reactive VOCs, such as benzene, toluene, and formaldehyde, that are also hazardous air pollutions (HAP).

Table 4 – VOC and $NO_X$ Emissions for Existing Minor Sources on Indian Country Lands within the

[17] Utah Administrative Code Chapter R307-401 (*Permits: New and Modified Sources*), available online at http://www.rules.utah.gov/publicat/code/r307/r307.htm, accessed October 14, 2015.
[18] Utah Administrative Code Chapter R307-500 Series (*Oil and Gas*), available online at http://www.rules.utah.gov/publicat/code/r307/r307.htm, accessed October 14, 2015.
[19] Existing source registrations are required to be submitted to the EPA under the Federal Indian Country Minor NSR Program at 40 CFR 49.160.
[20] In developing this proposed rule, we conducted an analysis of the registration information, including production and emission data, from sources on the Uintah and Ouray Indian Reservation. Data analyzed is current as of the 1st quarter of calendar year 2015. The data and our analysis can be found in the docket for the proposed rule, Docket ID: EPA-R08-OAR-2015-0709, which can be accessed at http://www.regulations.gov.

U&O Reservation[21]

| Source Category | VOC Emissions (tpy) | Percent of Total | $NO_X$ Emissions (tpy) | Percent of Total | Reactive HAP Emissions | Percent of Total |
|---|---|---|---|---|---|---|
| Oil and Natural Gas Production | 63,140 | >99 | 11,168 | >99 | 8,896 | 100 |
| Nonmetallic Mineral Mining | 9 | <1 | 3 | <1 | 0 | 0 |
| **TOTAL** | **63,149** | | **11,171** | | **8,896** | |

In order to develop appropriate requirements for the control of emissions from the oil and natural gas production operations in the Uinta Basin on the Indian country lands within the U&O Reservation, we consulted the oil and gas sector emissions inventory study by the WRAP, introduced previously in this document[22], to determine the equipment and operations that generate the largest portion VOC emissions from these sources. The inventory indicates that the highest VOC emissions from existing oil and natural gas sources in the Uinta Basin, of which 80 percent are on the Indian country lands within the U&O Reservation (see Table 1), are emitted from (top 6 in order of highest to lowest): (1) unpermitted crude oil and condensate storage tanks; (2) unpermitted glycol dehydrators; (3) unpermitted pneumatic devices; (4) unpermitted pneumatic pumps; (5) individual emissions units or activities controlled through PSD minor NSR, and Title V permits issued by the EPA or the UDEQ; and (6) unpermitted fugitive emissions (See Table 5).

Table 5 – 2012 VOC Emissions (tpy) by Oil and Natural Gas Source Category for Uinta Basin.[23]

| Equipment/Activity Description | Tribal Airshed | Percent of Total | Non-Tribal Airshed | Percent of Total |
|---|---|---|---|---|
| Unpermitted Crude Oil Tanks | 11,758 | 12 | 8,965 | 36 |
| Unpermitted Condensate Tanks | 20,151 | 20 | 1,568 | 6 |
| Unpermitted Glycol Dehydrators | 26,548 | 26 | 4,117 | 16 |
| Unpermitted Pneumatic Pumps | 11,339 | 11 | 2,982 | 12 |
| Unpermitted | 20,010 | 20 | 5,073 | 20 |

[21] Source: Data from existing source registration reports submitted under 40 CFR 49.160 of the Federal Indian Country Minor NSR Program by operators of sources on the Indian country lands within the U&O Reservation. HAP emissions for glycol dehydrators and condensate/crude oil tanks either reported directly in the registrations or extrapolated from reported VOC emissions and supporting documentation. HAP emissions for pneumatic pumps, pneumatic controllers, and LDAR were estimated. HAP emissions total excludes HAP from combustion (i.e. engines, heaters, heater treaters, etc.). Analysis of the data can be viewed in a spreadsheet in the docket for this rulemaking titled "EmissionReductionAnalysis.xlsx."
[22] See footnote 9.
[23] Source: See footnote 9.

| | | | | |
|---|---|---|---|---|
| Pneumatic Devices | | | | |
| Permitted Sources (UDEQ or EPA) | 4,355 | 4 | 0 | 0 |
| Unpermitted Fugitives | 2,564 | 3 | 647 | 3 |
| Unpermitted Venting – Compressor Startups/Shutdowns | 2,197 | 2 | 336 | 1 |
| Unpermitted Compressor Engines | 487 | <1 | 209 | 1 |
| Unpermitted Artificial Lift Engines | 542 | 1 | 413 | 2 |
| Unpermitted Other Equipment/Activitie s | 2,369 | 2 | 865 | 3 |
| **TOTAL** | **102,319** | | **25,175** | |

We believe that it is appropriate to focus on the oil and natural gas production operations that have been identified as contributing the largest portion of VOC emissions on the Indian country lands within the U&O Reservation and in shared airsheds of Utah. Based on a review of the air quality status on the Indian country lands within the U&O Reservation and existing emissions inventories, we determined that VOC emission control requirements for crude oil, condensate, and produced water storage tanks, glycol dehydrator still vents, pneumatic pumps and pneumatic controllers are appropriate for this FIP.

### 3. Development of Requirements

a. <u>Review of State Air Agency Rules and/or Guidance for the Oil and Natural Gas Sector</u>

In order to determine what level of control would effectively create consistent regulatory emission control requirements and air quality protection between our CAA jurisdiction on the Indian country lands within the U&O Reservation and the UDEQ's CAA jurisdiction elsewhere in Utah, we reviewed Utah Oil and Gas Rules. We also reviewed the Utah Permitting Rules. Lastly, we reviewed other state oil and natural gas production-related regulations in Region 8 for areas that are similar to Utah in industry, meteorology, or air quality concerns to ensure the proposed requirements are reasonably achievable due to the common use of the control technologies in those regulations.

We reviewed rules and guidance from nearby state agencies including the Wyoming Department of Environmental Quality's Air Quality Division (WDEQ),[24] the Colorado Department of Public Health

[24] WDEQ AQD. Nonattainment Area Regulations Chapter 8, Section 6. Revised June 30 2015. Available online at: http://soswy.state.wy.us/Rules/default.aspx. Accessed October 19, 2015. State-only rule.

and Environment's Air Pollution Control Division (CDPHE),[25] We determined that it was not necessary to review state and local rules that address non-VOC pollutant emissions, non-ozone nonattainment area requirements, or non-ozone specific localized air quality concerns, unless similar such concerns are also present on Indian country lands within the U&O Reservation, and relevant control requirements in the other state rules apply to the same emission units this rule seeks to address. Therefore, in addition to UDEQ requirements, we focused on the requirements of the WDEQ for the Upper Green River Basin ozone nonattainment area and the requirements of the CDPHE in the Denver Metro and North Front Range ozone nonattainment area, as those two areas have experienced similar ozone issues attributable oil and natural gas production activities that have been addressed through state and local rules.

Copies of all the state and local agency rules that we considered in this process and other supporting documentation are included in the docket for this rule.

Table 6 summarizes the VOC control requirements for existing oil and natural gas production operations in the Uinta Basin in Utah, the Upper Green River Basin ozone nonattainment area in Wyoming, and the Denver Metro and North Front Range 8-Hour Ozone Control Area and Nonattainment Area in Colorado. Copies of all the state and local agency rules that we considered in this process and other supporting documentation are included in the docket for this rulemaking.

Table 6 - Summary of VOC Control Requirements in Comparable State Rules or Guidance

| Rule or Guidance | VOC Control Requirements for Existing Oil and Natural Gas Production Operations |
|---|---|
| UDEQ Utah Administrative Code, Rule R-307-501 to -504 Oil and Gas Industry: General Requirements, Pneumatic Controllers, Flares, Tank Truck Loading. | • All crude oil, condensate, and intermediate hydrocarbon liquids collection, storage, processing, and handling operations must be properly operated and maintained to minimize VOC emissions.<br>• Air pollution control equipment must be properly designed operated, and maintained in a manner consistent with good air pollution control practices for minimizing emissions and to achieve the control efficiency rates established in rules or approval orders and handle reasonably foreseeable fluctuations in emissions of VOC during normal operations (fluctuations in emissions that occur when the separator dumps into the tank are considered reasonably foreseeable).<br>• Accelerates the adoption of requirements for low-bleed or no-bleed pneumatic controllers in NSPS OOOO, by April 1, 2017.<br>• All new and existing flares must be equipped with an operational automatic igniter by April 1, 2017.<br>• Tank truck loading required to be submerged fill/bottom fill. |

[25] CDPHE APCD. Oil and gas air emissions requirements (Regulation 7 Section XVII). Available online at: https://www.colorado.gov/pacific/cdphe/aqcc-regs. Accessed October 21, 2015. State-only rule.

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|---|---|
| UDEQ Engineering Review: Site-Specific Approval Orders and General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery – BACT requirements review | • At sources where the aggregate actual VOC emissions are greater than or equal to 4 tpy, such emissions must be controlled with an enclosed combustor or flare or must be incorporated in a product.<br>• Annual Leak Detection and Repair (LDAR) for all sources with actual VOC emissions greater than 5 tpy, with frequencies for General Approval Order (GAO) sources (new and modified) changing based on crude oil and condensate throughput levels and number of leaks detected. |
| CDPHE Air Quality Control Commission Regulation Number 7, Section XII – Volatile Organic Compound Emissions from Oil and Gas Operations and Section XVII – Statewide Controls for Oil and Gas Operations and Natural Gas-fired Reciprocating Internal Combustion Engines | • NSPS OOOO incorporated by reference for storage vessels and pneumatic controllers.<br>• Section XII.H. – Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation or natural gas compressor station in the 8-Hour Ozone Control Area or any ozone nonattainment or attainment/maintenance area must reduce uncontrolled actual emissions of VOC by at least 90% on a rolling twelve-month basis through the use of a condenser or air pollution control equipment where the actual uncontrolled emissions of VOC from the glycol natural gas dehydrator are equal to or greater than 1 tpy; and the sum of actual uncontrolled emissions of VOC from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tpy.<br>• Section XVII.D. (overlaps with Section XII.H. for 8-Hour Ozone Control Area or any ozone nonattainment or attainment/maintenance area) – Statewide, beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation or natural gas compressor station must reduce uncontrolled actual emissions of hydrocarbons by at least 95% on a rolling 12-month basis through the use of a condenser or air pollution control equipment where uncontrolled actual emissions of VOC from a single glycol natural gas dehydrator constructed before May 1, 2015 $\geq 6$ tpy, or $\geq 2$ tpy from a single dehydrator constructed on or after May 1, 2015 or that is located within 1,320 feet of building unit or designated outside activity area.<br>• LDAR program for well production facilities: Owners or operators of well production facilities must identify leaks from components using an approved instrument monitoring method. The frequency of inspections depends upon the well production, presence of storage tanks. Leaks must be identified utilizing EPA Method 21 monitoring, or other Division approved instrument based monitoring. First attempt to repair a leak must be made no later than five (5) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.<br>• All well pads that produce gas must be controlled or on pipeline<br>• Any combustion device used to control VOCs shall be enclosed, have no visible emissions during operation, and be equipped with and operate an auto-igniter.<br>• Operators must minimize well unloading and keep records.<br>• All liquid VOC transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. |

| | |
|---|---|
| WDEQ Nonattainment Area Regulations, Chapter 8, Section 6 - Upper Green River Basin permit by rule for existing sources | • Source-wide VOC flashing emissions greater than or equal to 4 tpy must be controlled by at least 98% (includes oil, condensate, produced water storage tanks, but also other emission units that experience flashing)<br>• Source-wide glycol dehydrator reboiler still vent and flash separator vent VOC emissions greater than or equal to 4 tpy must be controlled by at least 98%<br>• All pneumatic pump VOC emissions controlled by at least 98% or closed loop design<br>• All pneumatic controllers low or no-bleed design or closed-loop design<br>• Fugitive VOC emissions greater than 4 tpy must implement quarterly LDAR (protocol with only audio-visual-olfactory inspections not acceptable, must have some combination of Method 21 or optical gas imaging). |

b. Evaluation of State or Local Rules and/or Guidance Relevant to the Proposed Rule Requirements

We have developed requirements in the proposed FIP that reflect, to the extent practicable, the most relevant aspects of the state rules and guidance we reviewed that apply to existing oil and natural gas sources. However, we are proposing levels of control that seek primarily to protect air quality and to make emissions control requirements across the Uinta Basin consistent, where possible. The requirements in the proposed rule, therefore, are primarily consistent with UDEQ requirements for existing oil and natural gas sources in the Uinta Basin. The discussion that follows compares the UDEQ, WDEQ, and CDPHE regulations and guidance for controlling VOC emissions from specific types of emissions units and activities found at existing oil and natural gas sources on the Indian country lands within the Uintah and Ouray Indian Reservation.

*Storage Tanks*

When reviewing state regulations or guidance for crude oil, condensate, and produced water storage tanks, we focused on those of the three that might apply to the tank sizes that are typically constructed at oil and natural gas sources on Indian country lands within the U&O Reservation: primarily tanks with a storage capacity of 500 bbl each or less (approximately 21,000 gallons). The requirements for construction and emission control of storage tanks are fairly consistent among all state regulations and guidance reviewed in the three states, although there are varying degrees of minimum natural gas throughput, storage capacities, or annual flashing emissions below which the requirements do not apply or the control equipment may be removed.

The site-specific approval orders issued to existing oil and natural gas sources under the Utah Permitting Rules require reduction of VOC emissions by 98 percent using an enclosed combustor or open flare when the combined actual VOC emissions from all storage tanks, glycol dehydrator still vents, and pneumatic pumps are greater than or equal to 4 tpy. Additionally, the UDEQ allows maintenance of uncontrolled VOC emissions from the aggregate emissions of storage tanks, glycol dehydrators, and pneumatic pumps at less than 4 tpy, as demonstrated for more than 12 consecutive months, as an alternative standard to 98 percent VOC emission reduction from these sources. This alternative emission limit is consistent with the alternative emission limit for storage vessels in NSPS OOOO, which allows for maintenance of uncontrolled storage vessel VOC emissions below 4 tpy, as demonstrated by 12 consecutive months of emissions data as an alternative to the 95 percent VOC emission reduction requirement.[26]

The WDEQ for the Upper Green River Basin ozone nonattainment area requires 98 percent VOC reduction for existing storage tanks with potential emissions[27] greater than 4 tpy. The CDPHE for the Denver Metro and North Front Range ozone nonattainment area requires condensate tank batteries (whether one tank or more) with uncontrolled VOC emissions greater than 6 tpy (or the aggregate of tank emissions greater than 5 tpy if within ¼ mile of a building unit or designated outside activity area) to reduce emissions by 95 percent.

In conclusion, for storage tanks, we found that our proposed requirements in this FIP are within the same range with these state requirements.

*Glycol Dehydrators*

In addition to the UDEQ regulations for glycol dehydrators previously discussed above, we also compared WDEQ and CDPHE regulations for glycol dehydrators and found that our requirements are in the same range as the state requirements. The WDEQ also requires 98 percent control of VOC emissions from all existing glycol dehydrators in the Upper Green River Basin ozone nonattainment area that emit greater than 4 tpy. The WDEQ allows control equipment removal if aggregate storage tank emissions or glycol dehydrator emissions at a source decline to and are reasonably expected to remain below 4 tpy. This is consistent with both UDEQ requirements. Beginning in May 2008, for glycol dehydrators located within the Denver Metro and North Front Range 8-Hour Ozone Control Area or any ozone nonattainment or attainment/maintenance area, where actual individual uncontrolled VOC emissions are greater than or equal to 1 tpy and aggregate emissions of all units at a site are greater than 15 tpy (including individual units less than 1 tpy), the CDPHE required VOC emissions to be reduced by at least 90 percent through the use of a condenser or air pollution control equipment. Subsequently, beginning in May 2015, the CDPHE began requiring emissions from glycol dehydrators statewide to be reduced by 95 percent on a rolling 12-month basis through the use of a condenser or air pollution control equipment, where actual uncontrolled VOC emissions of a single dehydrator constructed before May 1, 2015 are greater than or equal to 6 tpy, or greater than or equal to 2 tpy if constructed on or after May 1, 2015.

*Pneumatic Pumps*

In addition to the UDEQ regulations for pneumatic pumps previously discussed above, we also compared WDEQ and CDPHE regulations for pneumatic pumps and found that our proposed requirements are in the same range as the state requirements. The WDEQ requires 98 percent VOC control or recovery of emissions to be used in a process or product for pneumatic pumps, or the use of non-pneumatic pumps. The CDPHE does not specifically address pneumatic pumps in its regulations.

[26] The Federal Register notice for the "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards; Proposed Rule", at 78 FR 22126, April 12, 2013, discusses the rationale for this proposed alternative storage vessels standard. The final rule was subsequently published in the Federal Register on September 23, 2013 (78 FR 58416).

[27] Potential to emit is calculated assuming no control devices are in place.

Therefore, for this equipment, we also found that we are within the same range when you compare our proposed rule with these requirements.

*Pneumatic Controllers*

The Utah Oil and Gas Rules require all existing pneumatic controllers to comply with the requirements for pneumatic controllers in NSPS OOOO. The WDEQ and CDPHE both require that all existing pneumatic controllers must be low or no bleed.

*Fugitive Emissions Monitoring*

The site-specific approval orders issued to existing oil and natural gas sources under the Utah Permitting Rules require annual fugitive emissions equipment component leak detection using EPA Method 21 or optical gas imaging, and repair of identified leaks. The GAO for new sources requires fugitive emissions component leak inspection frequency ranging from once every 12 months to once every 3 months, based on the barrels of crude oil and condensate generated at the source annually, with changes in frequency provided for based on the number of leaks detected. The WDEQ requires owners or operators to conduct quarterly equipment leak inspections at UGRB sources where fugitive emissions are > 4 TPY VOC using auditory, visual, and olfactory (AVA), Method 21, optical gas imaging or some combination but AVO only inspections are not allowed. The CDPHE Regulation 7 requires owners or operators of well production facilities to identify leaks from fugitive emission components using AVO monthly and an approved instrument monitoring method with varying frequency. Owners or operators of compressor stations must conduct quarterly inspections. The frequency of inspections at well sites depends upon the source VOC emissions and, if storage tanks are present, the emissions from the highest emitting tank. Leaks from components must be identified utilizing optical gas imaging (i.e., infra-red camera), EPA Method 21 monitoring, or other Division-approved instrument based monitoring device or method. CDPHE Regulation 7 also requires repair of leaking equipment which is dependent upon the type of monitoring device or method. Therefore, for leak detection, we also found that we are within the same range when comparing our proposed rule with these requirements.

Ultimately, we decided that in order to provide the necessary VOC emission reductions from existing oil and natural gas sources, while also striving for regulatory consistency across jurisdictional boundaries, the best VOC control requirements to propose are those as consistent as possible with UDEQ requirements for existing sources in the Uinta Basin. However, in some cases, such as the required frequency of fugitive emissions monitoring, we have proposed fugitive emissions monitoring requirements that are consistent with NSPS OOOO and OOOOa, and are more stringent than the UDEQ requirements for existing sources, new, and modified sources.[28]

## IV. Economic Impact Analysis

[28] The proposed FIP requires semi-annual fugitive emissions monitoring for well sites, quarterly fugitive emissions monitoring for compressor stations, and monitoring frequencies for natural gas processing plants in accordance with NSPS VVa. Existing oil and natural gas sources that are covered under UDEQ site-specific approval orders are subject to annual fugitive emissions monitoring. New oil and natural gas sources that are covered under the UDEQ's GAO for a Crude Oil and Natural Gas Well Site and/or Tank Battery may be required to perform LDAR monitoring more frequently than annually if the projected annual throughput of crude oil and condensate combined is greater than or equal to 25,000 barrels.

## 1. Introduction

In the following section, we provide our evaluation of the cost impact of the control strategies and technologies required under the proposed FIP. Copies of the supporting documentation, sources of cost estimates, emission reduction estimates, and source registration information, are available in the docket for this rule: Docket ID EPA-R08-OAR-2015-0709.

To estimate the total cost of the rule, as well as the dollar cost per ton of VOC control, the EPA relied on existing cost analyses done in support of the 2015 proposed NSPS OOOO revisions and NSPS OOOOa,[29] the 2015 draft Control Technique Guidelines (CTG) for existing sources in nonattainment areas,[30] and the 2012 Colorado Regulation Number 7.[31] The annual cost impact on a given operator is expected to be highly variable depending on the size of an operator's existing fleet of sources, the site specific conditions, and existing control equipment present at the fleet's sources. Due to this degree of variability, we generally apply conservative assumptions in our cost analysis so that the actual costs to any single operator will likely be less than we estimate. Additionally, many of the strategies and controls required by the proposed FIP will benefit operators by reducing the amount of gas vented to the atmosphere. These savings are not included in the cost analysis, but would increase the cost effectiveness of the rule as owners and operators would gain revenue from the sale of the gas not vented to the atmosphere.

In the following discussion, the cost estimates are discussed for each emission source and control technology. To estimate the cost of a particular equipment or control strategy, we rely on the draft CTG the EPA made available for comment in August 2015. This document includes the latest understanding of equipment capital costs, as well as installation, maintenance, and record-keeping costs. Control costs for some proposed FIP requirements (e.g., controlling emissions from dehydrators) are not provided in the draft CTG. For sources and control strategies not covered by the draft CTG, the EPA relies instead on the Colorado Regulation 7 Cost Analysis, which is a cost study based on Colorado's experience implementing its oil and natural gas regulation, and which, like the draft CTG, account for retrofit costs on existing sources. The study is regarded as the most recent and comprehensive analysis of costs experienced by operators from implementing a range of oil and natural gas control strategies and equipment. Many of the cost estimates in the EPA's draft CTG relied on the estimates derived in the Colorado Regulation 7 cost analysis. The EPA, therefore, believes that it is appropriate to rely on the Colorado Regulation 7 cost analysis to provide cost information for sources and control technologies not included in the draft CTG.

With respect to health and welfare benefits expected from this rulemaking, we are providing a qualitative discussion only as we currently lack the tools and information necessary to quantitatively estimate the benefits of this proposed rulemaking. Specifically, we currently lack a dollar per ton of

[29] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector: http://www3.epa.gov/airquality/oilandgas/pdfs/og_prop_ria_081815.pdf

[30] Control Techniques Guidelines for the Oil and Natural Gas Industry (Draft): http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf. We acknowledge that both the costs and cost per ton of VOC control have received significant "adverse" comments and may be revised.

[31] Initial Economic Impact Analysis For Proposed revisions to Colorado Air Quality Control Commission Regulation Number 7: https://www.colorado.gov/pacific/sites/default/files/062_R7-Initial-EIA-request-11-21-13-26-pgs-062_1.pdf

VOC reduced number that could be readily applied to this analysis. While we expect that the avoided VOC emissions will result in improvements in air quality and reduce health and welfare effects associated with exposure to ozone, we have determined that quantification of the VOC-related health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that these benefits do not exist; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. With the data available, we are not able to provide a credible health benefits estimates for this rule, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with VOC reductions.

However, we do know that the majority of the health benefits of the proposed rulemaking will be expressed in the reduction of ozone concentrations in the Uinta Basin. The Regulatory Impact Analysis[32] for the recently revised ozone NAAQS contains a detailed discussion of the current state of knowledge on the health benefits associated with reducing ambient levels of ozone air pollution. When we describe ozone health benefits, we generally group them in two categories: (1) reduced incidence of premature mortality from exposure to ozone and (2) reduced incidence of morbidity from exposure to ozone. Reductions in premature mortality can either occur as a result of reductions in short term exposures to ozone, which can benefits people at all ages. Or, reductions in premature mortality can occur over as a result of reductions in lifetime exposures to ozone (age 30 to 99). Reduced morbidity from reduced exposure can occur through reduced: (1) hospital admissions—respiratory (age > 65); (2) emergency department visits for asthma (all ages); (3) asthma exacerbation (age 6-18); (4) minor restricted-activity days (age 18–65); and (5) school absence days (age 5–17).

## 2. Scope of Proposed Rulemaking

To estimate the number of sources and equipment that could be impacted by the proposed FIP, the EPA relied on the existing minor source registration forms submitted by operators under the Federal Indian Country Minor NSR Program. Information is current as of the 1st Quarter of 2015. EPA will consider using updated activity and emissions information in the economic impact analysis if it becomes available after the rule has been proposed. As discussed in the proposed rule text, the EPA proposes to apply the FIP to existing sources with source-wide VOC emissions equal to or greater than five tpy. The EPA proposes that sources with source-wide VOC emissions greater than or equal to five tpy must implement a LDAR program. Additionally, under the proposed FIP, sources with source-wide VOC emissions greater than or equal to five tpy and aggregate VOC emissions from all storage tanks, dehydrators, and pneumatic pumps greater than or equal to four tpy must control the emissions from all storage tanks, dehydrators, and pneumatic pumps. Finally, to be consistent with Utah state regulations, the EPA proposes that all sources, regardless of VOC emissions, retrofit existing flares with auto igniters, practice submerged loading/unloading, and replace pneumatic controllers from high-bleed to low bleed. Based on the data submitted, the total count of sources that would likely be subject to this rulemaking is estimated at 3,410. An additional estimated 1,759 sources with source-wide VOC

[32] "Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone," U.S. Environmental Protection Agency, EPA-452/R-15-007, September 2015, http://www3.epa.gov/ozonepollution/pdfs/20151001ria.pdf.

emissions less than five tons would be required to retrofit existing flares with auto igniters, retrofit high-bleed pneumatic controllers, submerged tank loading/unloading, and properly maintained equipment.

The following types of control technologies apply to varying degrees to existing sources operating on the U&O Reservation:

- Installation of a combustor and retrofitting existing tanks to route tank emissions to the combustor;
- Installation of a combustor only (no tanks present);
- Routing of emissions from any dehydrators to a combustor;
- Routing of emissions from any pneumatic pumps to a combustor;
- Conversion of existing high-bleed pneumatic controllers to low-bleed pneumatic controllers;
- Retrofitting of all existing flares with auto-igniters; and
- Implementation of a leak detection and repair program using OGI equipment (e.g., IR camera).

Additionally, the following requirements apply to all sources operating on the U&O Reservation:

- Implementation of a policy of submerged tank loading/unloading; and
- Proper maintenance of equipment.

In the following discussion we assess the individual costs for each control technology requirement. A summary table is provided at the end of Section IV describing total annualized costs for implementing the FIP. Finally, Section IV discusses the expected emission reductions and presents an expected dollar per ton cost of control.

### 3. Cost Analysis

As noted earlier, we utilized cost information from the draft CTG and Colorado Regulation 7 cost analysis, which follows. It is considered the best available data on the control costs required by this proposed FIP. We then determined a representative and appropriate total annualized cost for each of the relevant control technologies and strategies.

a. <u>Installation of a new combustor and retrofitting existing tanks:</u>

About 2,660 sources on the Indian country lands within the U&O Reservation would be required to add a new combustor to control VOC emissions from tanks. Using information from the draft CTG,[33] the EPA estimates that the total capital cost to install a new combustor and retrofit existing tanks is $100,986. Table 7 contains the breakdown of this estimate.

Table 7 – Total Capital Investment – Adding New Combustor and Retrofitting Existing Tanks

| | |
|---|---|
| ***Capital Costs Items*** | |
| Combustor | $18,169 |

[33] Capital and recurring costs used from Table 4-5 of the draft CTG.

| | |
|---|---|
| Freight and Design | $1,648 |
| Auto Igniter | $1,648 |
| Surveillance System | $3,805 |
| Combustor Installation | $6,980 |
| Storage Vessel Retrofit | $68,736 |
| Total Capital Investment | $100,986 |

To calculate an annualized cost, the equipment is assumed to have a 15 year lifetime and 7 percent rate of return. Additionally, annual recurring costs are included: operating labor, maintenance, pilot fuel, and data management. Shown in Table 8, the total annualized costs of adding a new combustor and retrofitting existing tanks is calculated to be $22,228 per source.

Table 8 – Annual Costs - Adding New Combustor and Retrofitting Existing Tanks

| ***Annual Costs Items*** | |
|---|---|
| Operating Labor | $5,155 |
| Maintenance | $4,160 |
| Pilot Fuel | $768 |
| Data Management | $1,057 |
| Capital Recovery (7 percent interest, 15 year equipment life) ($/yr) | $11,088 |
| ***Total Annual Costs ($/yr)*** | $22,228 |

b. Installation of a new combustor only:

Some sources in the U&O Reservation will be required to install a new combustor; however, they do not have tanks on-site that require retrofitting. These sources would be required to add a new combustor to control dehydrator and pneumatic pump emissions. Using information from Table 8, the EPA removed the cost to retrofit the storage vessel and calculated the total capital cost of installing only a new combustor. Table 9 describes the breakdown of this estimate.

Table 9 – Total Capital Investment – Adding New Combustor Only

| ***Capital Costs Items*** | |
|---|---|
| Combustor | $18,169 |
| Freight and Design | $1,648 |
| Auto Igniter | $1,648 |
| Surveillance System | $3,805 |
| Combustor Installation | $6,980 |
| Total Capital Investment | $32,250 |

To calculate an annualized cost, the equipment is assumed to have a 15 year lifetime and 7 percent rate of return. Additionally, annual recurring costs are included: operating, labor, maintenance, pilot fuel, and data management. Shown in Table 10, the total annualized costs of adding a new combustor is calculated to be $14,681 per source.

Table 10 – Annual Costs - Adding New Combustor Only

| ***Annual Costs Items*** | |
|---|---|
| Operating Labor | $5,155 |
| Maintenance | $4,160 |
| Pilot Fuel | $768 |
| Data Management | $1,057 |
| Capital Recovery (7 percent interest, 15 year equipment life) ($/yr) | $3,541 |
| ***Total Annual Costs ($/yr)*** | $14,681 |

c. Routing emissions from any dehydrators to a combustor:

The proposed FIP requires that emissions from dehydrators at sources with source-wide VOC emissions greater than or equal to five tpy be routed to a combustor if the aggregate VOC emissions from all storage tanks, dehydrators, and pneumatic pumps at the source are greater than or equal to four tpy. The draft CTG does not include dehydrators in its control strategies discussion, and the Colorado Regulation 7 cost analysis does not separate out the costs of this particular scenario. The EPA assumes that the cost of routing a source's dehydrators to a combustor is significantly cheaper than the costs of retrofitting tanks ($68,736). Conservatively, we assume the costs are 25 percent of the costs of retrofitting a tank – a capital investment of $17,184. Adding in freight and design – assumed to be the same as retrofitting existing tanks – we estimate the total capital investment to be $18,832. After annualizing this cost over 15 years at a 7 percent rate of return, we estimate the total annualized costs of connecting a source's dehydrators to a combustor to be $2,068.

d. Routing emissions from any pneumatic pumps to a combustor:

The proposed FIP requires that emissions from pneumatic pumps at sources with source-wide VOC emissions greater than or equal to five tpy be routed to a combustor if the aggregate VOC emissions from all storage tanks, dehydrators, and pneumatic pumps at the source are greater than or equal to four tpy. The draft CTG calculate an annualized cost of $285 per pneumatic pump[34] to route emissions to a combustor. From an analysis of existing minor source registration data for the Indian country lands within the U&O Reservation, we estimate that on average, there are 3.5 pneumatic pumps per source. The average annualized cost of controlling pneumatic pumps is, therefore, estimated to be $998 per source.

e. Converting high-bleed pneumatic controllers to low-bleed:

The EPA acknowledges that many sources have already retrofitted to low-, or no-bleed pneumatic

[34] From Table 7-4 of the draft CTG.

controllers either voluntarily, or through a consent decree[35], or have intermittent controllers. The EPA conservatively assumes that 20 percent of the pneumatic controllers on the U&O Reservation are still high-bleed. Using the estimated source count of 5,169 from the registration data and an average count of 3.51 controllers per source, the EPA estimates that 3,629 pneumatic controllers on the U&O Reservation are high-bleed and will require retrofit to low-bleed or no-bleed. The draft CTG calculate an annualized cost of $296 per unit to replace a high-bleed controller with a low-bleed controller.[36] Therefore, the total cost to convert all existing high-bleed controllers to low-bleed controllers is estimated at $1,074,184.

f. Retrofitting all existing flares with auto-igniters:

The proposed FIP requires existing sources that may already have a combustor or flare, to retrofit that device with an auto-igniter. The draft CTG do not explicitly describe retrofitting an existing flare with an auto-igniter. Therefore, for this cost analysis, we reference the Colorado Regulation 7 Cost Analysis.[37] We estimate the initial capital cost is $1,648. We estimate additional costs associated with the freight, engineering, and installation of the auto-igniter to be $700. Annualizing the total capital cost over 15 years at 5 percent rate of return, the total annualized cost of the equipment is $275. We estimate annual operation and maintenance costs to be $200. The total annualized cost of retrofitting a flare is estimated to be $475 per source, which assumes that most sources will only have one combustion device and multiple retrofits will not be necessary for most sources.

g. Implementing a leak detection and repair program:

The proposed FIP includes a new requirement for operators to develop a leak detection and repair program for well sites and compressor stations. For our cost analysis, we rely on cost information described in the draft CTG.[38] The particular programs that would be required under this FIP are 1) An optical gas imaging (OGI) survey done semi-annually for well sites with actual annual VOC emissions greater than or equal to five tpy and 2) An optical gas imaging (OGI) survey done quarterly for compressor stations (gathering and boosting stations) with actual annual VOC emissions greater than or equal to five tpy. Any leaks detected using OGI must then be repaired and confirmed using Method 21. The capital costs for implementing LDAR for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program; which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of an OGI monitoring device. The total annualized cost assumes an equipment lifetime of 8 years at 7 percent interest. Using the CTG cost information, the EPA estimates that the annualized cost of implementing an LDAR program with OGI detection at well sites to be $2,230 per well. Assuming an average of 1.3 wells per source,[39] the total annualized cost per source is estimated to be $2,899. Additionally, EPA estimates that the annualized cost of implementing

[35] Such as the CAA Consent Decrees with Kerr-McGee, Gasco, Miller Dyer/Whiting, Dominion/XTO, Bill Barrett and Monarch which required all high-bleed pneumatics be retrofit with low- or no-bleed and required installation of such for all new sources.
[36] From Table 6-4 of the draft CTG.
[37] Information from Table 28 of Colorado Air Quality Commission Initial Economic Impact Analysis Regulation 7
[38] From Table 9-12 and 9-13 of the draft CTG.
[39] An average of 1.3 wells per source was assumed through an analysis of data submitted in the existing minor source registrations required under the Tribal Minor NSR Program.

an LDAR program with OGI detection at compressor stations to be $27,396 per site.

h. Submerged tank loading/unloading:

The EPA assumes that there is no significant additional cost associated with the practice of submerged tank loading and tank unloading. We consider this to be a good operating practice and we believe that it should not add additional cost for operators.

i. Proper maintenance of equipment:

We expect that operators will use good engineering practice with respect to the maintenance of well-site equipment to ensure that it is properly functioning. The EPA does not expect any significant increase to costs associated with properly maintaining equipment.

## 4. Annualized Cost Impact from the Rule

Generally, the EPA recognizes that, under the proposed rule, the existing sources can be broken down into eight potential categories. Using the cost information described above and the source counts within each source category, we calculated the total cost of the proposed rule. Table 11 shows each source category, and the applicable control technology. Table 12 shows the appropriate cost information applied to each source category to calculate a total annualized cost (in 2012 dollars).

Table 11 – Source Category and Applicable Control Technology

| Source Category | Applicable Control Technology | | | | | |
|---|---|---|---|---|---|---|
| | Combustor and retrofit tanks | Combustor only | Route Dehydrator to Combustor | Route Pneumatic Pump to Combustor | LDAR | Retrofit Existing Flares w/ Auto Igniter |
| Category 1: Sources >= 5 source wide VOC & aggregate VOC >=4. Tanks on site, no existing tank controls, no dehydrator. | X | | | X | X | |
| Category 2: Sources >= 5 source wide VOC & aggregate VOC >=4. Tanks on site, no existing tank controls, w/ dehydrator. | X | | X | X | X | |
| Category 3: Sources >= 5 source wide VOC & aggregate VOC >=4. No tanks on site, no existing tank controls, w/ dehydrator. (All of these sources had dehys on site & no tank controls). | | X | X | X | X | |
| Category 4: Sources >= 5 source wide VOC & aggregate VOC >=4. Tanks on site, w/ existing tank controls. (Assumed any dehydrators & pumps already routed). | | | | | X | X |

| | | | | | | |
|---|---|---|---|---|---|---|
| Category 5: Sources >= 5 source wide VOC & aggregate VOC <4. Tanks on site, w/ existing tank controls. | | | | | **X** | **X** |
| Category 6: Sources >= 5 source wide VOC & aggregate VOC <4. Tanks on site, no existing tank controls. | | | | | **X** | |
| Category 7: Sources <5 source wide VOC. Tanks on site, w/ existing tank controls. | | | | | | **X** |
| Category 8: Sources <5 source wide VOC. Tanks on site, no existing tank controls. | | | | | | |
| All existing high-bleed pneumatic controllers to be retrofit with low-bleed (cannot allocate to particular sources) | | | | | | |

Table 12 - Total annualized cost for each category

| Source Category | Annual cost / source (2012 $) | Count of sources | Total Annual Cost (2012 $) |
|---|---|---|---|
| Category 1: Sources >= 5 source wide VOC & aggregate VOC >=4. Tanks on site, no existing tank controls, no dehydrator. | $23,225 | 1,177 | $27,336,084 |
| Category 2: Sources >= 5 source wide VOC & aggregate VOC >=4. Tanks on site, no existing tank controls, w/ dehydrator. | $25,293 | 1,484 | $37,534,623 |
| Category 3: Sources >= 5 source wide VOC & aggregate VOC >=4. No tanks on site, no existing tank controls, w/ dehydrator. (All of these sources had dehys on site & no tank controls). | $17,746 | 356 | $6,317,586 |
| **# Sources that add a combustor** | | **3,017** | |
| Category 4: Sources >= 5 source wide VOC & aggregate VOC >=4. Tanks on site, w/ existing tank controls. (Assumed any dehydrators & pumps already routed). | $475 | 182 | $86,450 |
| Category 5: Sources >= 5 source wide VOC & aggregate VOC <4. Tanks on site, w/ existing tank controls. | $475 | 6 | $2,850 |
| **# Sources that retrofit existing flare w/auto igniter** | | **188** | |
| Category 6: Sources >= 5 source wide VOC & aggregate VOC <4. Tanks on site, no existing tank controls. | - | 205 | - |
| **# Sources >= 5 Source wide VOC** | | **3,410** | |
| Category 7: Sources <5 source wide VOC. Tanks on site, w/ existing tank controls. | $475 | 44 | $20,900 |
| Category 8: Sources <5 source wide VOC. Tanks on site, no existing tank controls. | - | 1,715 | - |
| **# Sources < 5 Source wide VOC** | | **1,759** | |
| LDAR at well sites | **$2,899** | **3,375** | **$9,784,125** |
| LDAR at compressor stations | **$27,396** | **35** | **$958,860** |
| All existing high-bleed pneumatic controllers to be retrofit with low-bleed (cannot allocate to particular sources) | | **-** | $1,074,184 |
| **TOTAL # Sources and Annualized Cost (2012 $)** | | **5,169** | **$83,115,662** |

The net impact from the rulemaking was determined to be less than $100 million, and therefore does not require a more comprehensive Regulatory Impact Assessment (RIA) under Executive Order 12866. We believe that it is likely that the actual cost of the rule is lower than the estimated $78 million since conservative assumptions were used when more accurate data was not available. Additionally, the cost savings to operators from the reclamation of lost product was not considered.

## 5. Capital Cost Impact of the Rule

Although not specifically required, the EPA performed an analysis to calculate the capital costs that the EPA expects all operators on the U&O Reservation to incur. This includes the capital investments in equipment required to fulfill the requirements of the FIP. Since there will be an 18 month grace period allowed under the rule, as well as temporary waivers, the EPA assumes that equipment costs will be distributed evenly across a period of three years. Table 13 presents a summary of total capital costs by control technology type. The total capital cost of the rule is estimated to be $357,796,493.

Table 13 – Total Capital Cost by Control Technology Type

| Control Technology Type | Estimate Number of Units Controlled | Capital Cost Per Unit | Total Cost |
|---|---|---|---|
| Low-Bleed Pneumatic Controller[40] | 3,629 | $ 2,698 | $ 9,791,042 |
| Optical Gas Imaging (LDAR) for Well-Sites[41] | 4,388 | $ 801 | $ 3,514,388 |
| Optical Gas Imaging (LDAR) for Compressor Stations[42] | 35 | $ 16,407 | $ 574,245 |
| Routing Pneumatic Pump Emissions to Existing Combustor[43] | 10,560 | $ 2,596 | $ 27,413,760 |
| Retrofit Existing Flares with Auto-Igniter[44] | 232 | $ 7,101 | $ 1,647,432 |
| Adding New Combustor and Retrofitting Tanks[45] | 2,661 | $ 100,986 | $ 268,723,746 |
| Adding New Combustor Only[46] | 356 | $ 32,250 | $ 11,481,000 |
| Routing Dehydrator Emissions to Combustor[47] | 1,840 | $ 18,832 | $ 34,650,880 |
| **Total Capital Cost of Rule** | | | **$ 357,796,493** |

[40] From CTG, table 6-4.
[41] From CTG, table 9-12
[42] From CTG, table 9-13
[43] Determined using a ratio of annualized cost to capital cost; CTG table 7-4.
[44] From CTG, table 4-5. Capital cost for freight and design, auto igniter, and surveillance system.
[45] From CTG, table 4-5.
[46] From CTG, table 4-5. Capital cost excluding retrofitting tank cost.
[47] From CTG, table 4-5. Conservatively uses 20% of cost of retrofitting existing tanks.

## 6. Cost of Control

To determine a cost of control (dollars per ton of VOC reduced), it is necessary to estimate the total expected emissions reduced through the FIP. For each of the required control technologies, the EPA calculated an expected tpy VOC reduction number.

*Controlling Dehydrators*

Using emissions information submitted under the Tribal Minor NSR Program, we estimate that the total VOC emissions from all sources containing dehydrators is 15,661 tpy. Using a 98 percent combustion efficiency after installing a combustor (or routing to existing combustor), the emissions are expected to be reduced by 15,348 tpy.

*Controlling Tanks*

Using emissions information submitted under the Tribal Minor NSR Program, we estimate that the total VOC emissions from all sources controlling tanks is 14,627 tpy. Using a 98 percent combustion efficiency after installing a combustor, the emissions are expected to be reduced by 14,334 tpy.

*Controlling Pneumatic Pumps*

Using emissions information submitted under the Tribal Minor NSR Program, we estimate that there are a total of 3,017 sources with pneumatic pumps that will be controlled under the proposed FIP. Using an average of 3.5 pneumatic pumps per source (also derived from registration data), the total number of pneumatic pumps in the U&O Reservation that will be impacted is 10,560. Applying information from Table 7-2 of the draft CTG, it is expected that uncontrolled emissions are 0.535 tpy for each pneumatic pump. The total emissions from controlling pneumatic pumps are therefore estimated to be 5,650 tpy. Using a 98 percent combustion efficiency after installing a combustor (or routing to existing combustor), the total emission reductions are estimated to be 5,537 tpy.

*Retrofitting Pneumatic Controllers*

Using emissions information submitted under the Tribal Minor NSR Program, we estimate that there are a total of 5,169 sources with pneumatic controllers. At those sources, we estimate that there are an average of 3.51 pneumatic controllers per source[48] – a total of 18,143 controllers in the U&O Reservation. Of those, we assume that 80 percent of these controllers have already been retrofit to low-bleed or are intermittent and that 20 percent have not. To estimate total emissions, and emission reductions, this analysis uses annual emission rates of 0.06 tpy and 1.47 tpy[49] for each low-bleed, and high-bleed unit, respectively. We project that retrofitting the remaining 20 percent of the controllers (3,629 units) will yield a total VOC reduction of 5,116 tpy.

*Optical Gas Imaging (LDAR)*

[48] 1.3 average # wells/source derived from registration data times 2.7 average # of controllers/well from "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers", Environmental Science, Allen, D., et al, Environ. Sci. Technol., 2015, 49 (1), pp 633–640.
[49] From CTG Table 6-2

Using information submitted under the Tribal Minor NSR Program, we estimate that there are a total of 3,375 sources with wells located in the U&O Reservation that will be required to implement a semi-annual OGI LDAR program. Assuming an average of 1.3 wells per source (derived from registration data), the total number of wells is estimated to be 4,388. From Table 9-12 of the draft CTG, we project that implementing a semi-annual OGI LDAR program will reduce VOC emissions by 0.47 tpy per well, yielding an emission reduction from sources with wells of 2,062 tpy. Using information submitted under the Tribal Minor NSR Program, we estimate that there are a total of 35 compressor stations located in the U&O Reservation that will be required to implement a quarterly OGI LDAR program. From Table 9-13 of the draft CTG, we project that implementing a quarterly OGI LDAR program will reduce VOC emissions by 7.81 tpy per compressor station, yielding an emission reduction from compressor stations of 273 tpy. Combined, the total VOC emissions reduced by implementing an OGI LDAR program at compressor stations and sources with well heads is 2,335 tpy.

Table 14 – Summary of VOC Reduced for Each Control Technology/Strategy

| | **VOC tpy reduced** |
|---|---:|
| Amount of VOC (tpy) reduced by controlling dehys | 15,348 |
| Amount of VOC (tpy) reduced by controlling tanks | 14,334 |
| Amount of VOC (tpy) reduced by controlling pumps | 5,537 |
| Amount of VOC (tpy) reduced by retrofitting controllers | 5,116 |
| Amount of VOC (tpy) reduced by LDAR[50] | 2,335 |
| Total amount of VOC (tpy) controlled/reduced | 42,670 |

Adding the reductions from all controls we propose to require in the FIP (as shown in Table 14), we project that 42,670 tpy of VOCs will be reduced. Using a total annualized cost of $83,115,662, the estimated cost of control per ton of reducing VOC is $1,948. We note that the emission reduction estimates are based on those that are expected to occur after full implementation of the FIP in 2018 following the 18-month implementation period.

## 7. Co-Benefits

The specific purpose for developing this proposed FIP is to regulate VOC emissions from oil and natural gas production operations on the Indian country lands within the U&O Reservation so as to improve ozone air quality. While this rule does not directly regulate other pollutants subject to regulation under the CAA, such as the greenhouse gases (GHGs) methane and $CO_2$, we project that it will produce significant reductions of GHGs because of the substantial methane reduction it will achieve as a co-benefit of the proposed VOC emission reduction. Additionally, control of VOCs also has the co-benefit of reducing HAPs, which also has public health and welfare benefits. Emissions of HAPs from the oil and gas sector can include benzene, toluene, ethylbenzene, xylene and hexane. We estimate that this FIP will also result in methane reductions of 83,635 tpy and HAP reductions of 8,720 tpy[51]. Also, the

[50] Estimates derived from application of speciation profiles provided in the registration data.
[51] Estimates derived from application of speciation profiles provided in the registration data.

methane reductions achieved through the retrofit or replacement of high-bleed pneumatic controllers and the implementation of an LDAR program would result in the conserving of about 2.1 billion cubic feet of gas annually.

## V. Regulatory Flexibility Act: Small Entity Impact Analysis

The Regulatory Flexibility Act (RFA) of 1980 as amended in 1996 by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires a federal agency to prepare a regulatory flexibility analysis of a rule unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. In order to determine whether this proposed rule has a significant economic impact on a substantial number of small entities, we performed a Small Entity Impact Analysis as outlined in the EPA's RFA guidance document.[52] This Small Entity Impact Analysis we have prepared describes the screening analysis we conducted, including how we estimated the number of affected small entities and how we examined the proposed rule's possible impact on these entities.

This proposed rule applies to existing oil and natural gas sources located on the Indian country lands within the U&O Reservation. To identify impacted entities, the EPA relied upon existing minor source registrations submitted by operators under the Federal Indian Country Minor NSR program at 40 CFR part 49. Under the Federal Indian Country Minor NSR Program, minor oil and natural gas sources constructed from August 30, 2011 up to March 2, 2016 must submit a registration to the Agency outlining source information including ownership, location, production, and emission information. As of the 1st Quarter of 2015, the minor source registration data identified over 5,100 minor oil and natural gas registrations on the Indian country lands within the U&O Reservation belonging to 25 businesses.

In accordance with the SBA definition of "small business," found in the Small Business Act (5 U.S.C. section 601(3)), each business and all of its affiliates are considered a single entity. The Small Business Administration's Size Standards[53] uses NAICS code to determine thresholds for what constitutes a "small business." The EPA utilized LexisNexis©, an online searchable resource of legal, business, and news records, to determine the number of employees and sales for each company and its affiliates operating on the Indian country lands within the U&O Reservation and, using the appropriate SBA threshold for the relevant NAICS codes, concluded that 11 companies out of the 25 companies qualified as a small business under the Small Business Act. See table 15.

Table 15 - Businesses with sources on the Indian country lands within the U&O Reservation

| Company Name | SBA "Small Business" |
|---|---|
| Anadarko Uintah Midstream, LLC | |

[52] U.S. Environmental Protection Agency (EPA). November 2006. Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as Amended by the Small Business Regulatory Enforcement Fairness Act. http://www2.epa.gov/reg-flex/epas-action-development-process-final-guidance-epa-rulewriters-regulatory-flexibility-act.
[53] U.S. Small Business Administration. February 26, 2016. Table of Small Business Size Standards Matched to North American Industry Classification Codes.

| | |
|---|---|
| Axia Energy II, LLC | X |
| Berry Petroleum Company, LLC | |
| Bill Barrett Corporation | X |
| Crescent Point Energy US Corp | X |
| El Paso Midstream Group, Inc. | |
| Enduring Resources, LLC | X |
| EOG Resources, Inc. | |
| EP Energy E&P Company LP | |
| Gasco Energy, Inc. | X |
| Kerr-McGee Oil and Gas Onshore LP | |
| Koch Exploration Company, LLC | |
| Mid-America Pipeline Company, LLC | |
| Monarch Natural Gas, LLC | X |
| Newfield Production Company | |
| QEP Energy Company | X |
| QEP Field Services Company | |
| Red Leaf Resources, Inc. | X |
| Red Rock Gathering Company, LLC | X |
| Rosewood Resources, Inc. | |
| Ultra Resources, Inc. | |
| US Oil Sands Utah, Inc. | X |
| Ute Energy, LLC | X |
| Whiting Petroleum Corporation | |
| XTO Energy, Inc. | |

The EPA relied on a direct compliance cost assessment to determine the economic impacts on the small businesses. A commonly used criterion to estimate the regulatory impact at the business level is the compliance costs as a percentage of annual sales. In order to determine the compliance costs as a percentage of annual sales, we first calculated the average annualized compliance cost per source by taking the total annualized cost of the rule ($83,115,662) and dividing by the total number of sources impacted by the rule (5,169) which gives an average annualized compliance cost per source of $16,080. This number was then multiplied by the number of sources owned by each business to give a compliance cost per business. Dividing this compliance cost per business by the annual sales determined the compliance costs as a percentage of annual sales for each business. See table 16.

Table 16 - Compliance Costs as a Percentage of Annual Sales

| **Operator Name** | **Compliance Costs as a Percentage of Annual Sales** |
|---|---|

| | |
|---|---|
| Axia Energy II, LLC | 0.36% |
| Bill Barrett Corporation | 0.02% |
| Crescent Point Energy US Corporation | 0.03% |
| Enduring Resources, LLC | 0.65% |
| Gasco Energy, Inc. | 0.43% |
| Monarch Natural Gas, LLC | 0.54% |
| QEP Energy Company | 0.32% |
| Red Leaf Resources, Inc. | 0.06% |
| Red Rock Gathering Company, LLC | 0.01% |
| US Oil Sands Utah, Inc. | 2.68% |
| Ute Energy, LLC | 0.00% |

The EPA employed criteria taken from EPA's RFA guidance document which is widely used in conducting such screening analyses to assess the severity of potential impacts. Businesses incurring costs less than 1 percent of sales are not expected to incur significant economic impacts due to the rule. Businesses with costs between 1 percent and 3 percent may incur potentially significant economic impacts. Businesses incurring costs exceeding 3 percent of sales are estimated to incur potentially significant economic impacts.

Ten companies incur costs less than 1 percent of sales and are not expected to incur significant impacts due to the rule. One company is projected to incur costs between 1 percent and 3 percent of sales and may incur potentially significant economic impacts. Taking into account the cost impacts, the percentage of small businesses which may be significantly impacted by this rule is 9 percent. Additionally, the EPA determined that US Oil Sands Utah Inc. registered a single source in the Indian country lands within the U&O Reservation. Currently, US Oil Sands Inc.'s website states that this source is under construction and is scheduled to begin oil production at the beginning of 2016. The EPA believes that upon oil production, sales for this business will increase which will lower the costs of compliance for US Oil Sands Utah Inc. and potentially lower the percentage of businesses impacted by the rule. In light of the production information for US Oil Sands Utah Inc. and given the small number of small businesses which may incur potentially significant economic impacts (one out of eleven), the EPA concludes that the rule is not expected to result in significant economic impacts for a substantial number of small companies.

## VI. Air Quality

### 1. Introduction

The air pollutants that are affected by this action are ozone and its precursor VOC. Ambient ozone is a secondary pollutant that is formed from precursor emissions of VOC and $NO_X$. High ambient ozone levels are typically observed in urban areas during stagnant meteorological conditions in the summer, and more recently, in areas of intensive oil and gas production in mountain basins that experience strong inversion conditions and snow cover during winter.

The State of Utah conducted special field studies in the Uinta Basin from 2011 to 2014 to understand the emissions sources that contribute to winter ozone. Reports for the winter ozone field study for each year are available on the UDEQ web page.[54] These studies found that the oil and gas production sector is the most significant anthropogenic contributor to NAAQS exceedances. The studies also concluded that ozone production is sensitive to reductions in VOC emissions but relatively less sensitive to reductions in $NO_x$ emissions. Based on the conclusions of these field studies, the EPA concluded that ozone levels in the Uinta Basin are being more significantly influenced by concentrations of VOC emissions from the accumulation of minor oil and natural gas production operations, rather than concentrations of $NO_x$ emissions from those same operations. The EPA determined that the proposed action will result in large reductions of VOC emissions and relatively small increases in NOx emissions, and this is expected to be beneficial for reducing ambient ozone and reducing the severity of exceedances of the of the 8-hour ozone NAAQS.

## 2. Current Air Quality Data in the Uinta Basin

a. <u>General description of the Uinta Basin</u>

The Uinta Basin is located in eastern Utah, east of the Wasatch Mountains and south of the Uinta Mountains. The southern rim of the basin is formed by the Tavaputs Plateau of the Book Cliffs. The central portion of the basin has an elevation of 5,000 to 5,500 feet, and the surrounding mountains form a natural basin that is conducive to persistent cold air pool inversion during winter. The climate of the Uinta Basin is semi-arid, with occasionally severe winter cold. The population of the Uinta Basin is approximately 50,000 with most of the residents located in the major towns of Vernal and Roosevelt in the northern portion of the basin. There is intensive energy development in the central and southern portion of the basin with primarily oil wells in the western portion and natural gas production wells in the eastern portion of the basin.

Impacts of the proposed action on ambient levels of ozone and nitrogen dioxide ($NO_2$) are evaluated relative to current monitored levels of ozone and $NO_2$ in the Uinta Basin. Table 17 lists the ozone and $NO_2$ monitoring sites operated by the Ute Indian Tribe and the UDEQ in the Uinta Basin. Table 18 also shows the dates for which regulatory ozone monitoring data was collected at these sites. In addition to the state and tribal ozone and $NO_2$ monitoring, three special ambient monitoring field studies were carried out during winters from 2012 to 2014 to investigate the emissions sources that cause high winter ozone concentrations in the Uinta Basin. These studies found that VOC and $NO_X$ emissions from intensive oil and gas developments in the basin can be trapped within a shallow inversion layer during persistent cold air pool conditions and that snow cover causes stronger inversion conditions and also increases surface albedo which enhance the photochemical reactions of VOC and $NO_X$ that produce ozone. Moreover, exceedances of the ozone NAAQS have only been observed in the Uinta Basin during winter in the presence of snow. The ozone NAAQS has not been exceeded in summer or in winter in the absence of snow cover.

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[54] Utah DEQ Uinta Basin winter ozone web page with reports on 2011 to 2014 field studies: http://www.deq.utah.gov/locations/U/uintahbasin/ozone/overview.htm.

Table 17 - List of Ozone and $NO_2$ Monitoring Sites Operated by the Tribe and State in the Uinta Basin.

| Site Name | AQS ID | Type | QAPP |
|---|---|---|---|
| Meeker, CO | 08-103-0005 | Non-EPA Federal | NPS/CO BLM |
| Rangely, CO | 08-103-0006 | Non-EPA Federal | NPS/CO BLM |
| Roosevelt | 49-013-0002 | Special Purpose | UDEQ |
| Fruitland | 49-013-1001 | Special Purpose | UDEQ |
| Myton | 49-013-7011 | Tribal | Ute Indian Tribe |
| Little Mountain | 49-047-0014 | Non-EPA Federal | USFS |
| Dinosaur NM | 49-047-1002 | Non-EPA Federal | NPS |
| Vernal 1 | 49-047-1003 | SLAMS | UDEQ |
| Vernal 2 | 49-047-1004 | SLAMS | UDEQ |
| Redwash | 49-047-2002 | Tribal | Golder/Ute Indian Tribe |
| Ouray | 49-047-2003 | Tribal | Golder/Ute Indian Tribe |
| Dragon Road | 49-047-5632 | Industrial | ENEFIT |
| Whiterocks | 49-047-7022 | Tribal | Ute Indian Tribe |

Table 18 - Annual 4th Daily Maximum 8-hour Ozone Concentrations and Ozone Design Values at Monitors in the Uinta Basin.

| Site Name | County | On U&O Reservation ? | AQS ID | Year | Annual 4th Highest Daily Maximum 8-hour Value (ppb) | Ozone Design Value (ppb)[55] |
|---|---|---|---|---|---|---|
| Meeker, CO | Rio Blanco | No | 08-103-0005 | 2010 | 66 | N/A |
| | | | | 2011 | 63 | N/A |
| | | | | 2012 | 64 | 64 |
| | | | | 2013 | 64 | 63 |
| | | | | 2014 | 62 | 63 |
| Rangely, CO | Rio Blanco | No | 08-103-0006 | 2010 | 58 | N/A |
| | | | | 2011 | 73 | N/A |
| | | | | 2012 | 69 | N/A |
| | | | | 2013 | 91 | 77 |
| | | | | 2014 | 62 | 74 |
| Roosevelt | Duchesne | No | 49-013-0002 | 2012 | 67 | N/A |
| | | | | 2013 | 104 | N/A |
| | | | | 2014 | 62 | 77 |
| Fruitland | Duchesne | No | 49-013-1001 | 2011 | 65 | N/A |

[55] Design value information from http://www3.epa.gov/airtrends/values.html.

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | 2012 | 70 | N/A |
| | | | | 2013 | 69 | 68 |
| Myton | Duchesne | Yes | 49-013-7011 | 2013 | 108 | N/A |
| | | | | 2014 | 67 | N/A |
| Dinosaur NM | Uintah | No | 49-047-1002 | 2014 | 64 | N/A |
| Vernal 1 | Uintah | No | 49-047-1003 | 2012 | 64 | N/A |
| | | | | 2013 | 102 | N/A |
| | | | | 2014 | 62 | 76 |
| Redwash | Uintah | Yes | 49-047-2002 | 2012 | N/A | N/A |
| | | | | 2013 | 63 | N/A |
| | | | | 2014 | 67 | N/A |
| Ouray | Uintah | Yes | 49-047-2003 | 2012 | N/A | N/A |
| | | | | 2013 | 92 | N/A |
| | | | | 2014 | 79 | N/A |
| Dragon Road | Uintah | Yes | 49-047-5632 | 2012 | 72 | N/A |
| | | | | 2013 | 82 | N/A |
| Whiterocks | Uintah | Yes | 49-047-7022 | 2013 | 95 | N/A |
| | | | | 2014 | 64 | N/A |

b. Current Ozone Levels in the Uinta Basin

The current NAAQS for ozone is 0.070 parts per million (ppm)[56]. Compliance with the ozone NAAQS is determined by comparison to a "design value" that is calculated as the three year average of the annual fourth highest daily maximum 8-hour average ozone concentration at each monitoring site. Table 18 lists the annual 4th highest daily maximum 8-hour average ozone concentration and the ozone design value for each regulatory monitor in the Uinta Basin based on air quality data from 2012-2014. Based on the most recent air quality monitoring data from 2012-2014[57], the ozone design values exceed the NAAQS at three monitoring sites in the Uinta Basin.

c. Current $NO_2$ Levels in the Uinta Basin

The current NAAQS for $NO_2$ is 100 parts per billion (ppb)[58]. Compliance with the $NO_2$ NAAQS is determined by comparison to a "design value" that is calculated as the three year average of the annual 98th percentile of the daily maximum 1-hour average $NO_2$ concentration at each monitoring site. Table 19 lists the annual 98th percentile of the daily maximum 1-hour $NO_2$ concentrations for each regulatory monitor in the Uinta Basin based on air quality data from 2012-2014. There were only two $NO_2$ monitors in the Uinta Basin which had collected sufficient data to calculate a valid design value in 2012-2014, but the available measurement data from all monitors indicates that current $NO_2$ levels in the Uinta Basin are well below the NAAQS.

[56] See 40 CFR 50.19.
[57] Current design value information is available at http://www3.epa.gov/airtrends/values.html
[58] See 40 CFR 50.11.

Table 19 - Annual 98th Percentiles of Daily Maximum 1-hour $NO_2$ concentrations and $NO_2$ design values at monitors in the Uinta Basin.

| Site Name | AQS ID | Year | Annual 98th Percentile Daily Maximum 1-hour Value (ppb) | $NO_2$ Design Value (ppb)[59] |
|---|---|---|---|---|
| Meeker, CO | 08-103-0005 | 2010 | 5.0 | N/A |
| | | 2011 | 5.7 | N/A |
| | | 2012 | 5.3 | N/A |
| | | 2013 | 4.2 | 5 |
| | | 2014 | 3.8 | 4 |
| Rangely, CO | 08-103-0006 | 2010 | 21.0 | N/A |
| | | 2011 | 23.4 | N/A |
| | | 2012 | 18.6 | N/A |
| | | 2013 | 24.2 | 22 |
| | | 2014 | 14.3 | 19 |
| Roosevelt | 49-013-0002 | 2012 | 32.8 | N/A |
| | | 2013 | 52.0 | N/A |
| | | 2014 | 34.3 | N/A |
| Fruitland | 49-013-1001 | 2011 | 16.0 | N/A |
| | | 2012 | 18.0 | N/A |
| | | 2013 | 20.0 | N/A |
| Myton | 49-013-7011 | 2013 | 29.5 | N/A |
| | | 2014 | 23.1 | N/A |
| Vernal 1 | 49-047-1003 | 2012 | 41.0 | N/A |
| | | 2013 | 78.0 | N/A |
| | | 2014 | 54.0 | N/A |
| Dragon Road | 49-047-5632 | 2012 | 12.0 | N/A |
| | | 2013 | 43.6 | N/A |
| Whiterocks | 49-047-7022 | 2013 | 19.5 | N/A |
| | | 2014 | 9.8 | N/A |

## 3. Qualitative Assessment of Air Quality Impacts

### a. Impacts on Ozone Levels in the Uinta Basin

The EPA reviewed data from existing minor source registrations and determined that a 98 percent control efficiency of VOC from source emissions will result in a total reduction of VOC emissions of 42,670 tpy. This includes a leak detection program that will result in VOC emissions reductions of 2,335 tpy and retrofit or replacement of high-bleed pneumatic controllers that would result in VOC emission

[59] Design value information from http://www3.epa.gov/airtrends/values.html.

reductions of 5,116 tpy. As noted above, based on the EPA 2011 National Emissions Inventory (NEI), total VOC emissions from oil and gas production in the Uinta Basin were 115,527 tpy, compared to a basin-wide total of 289,226 tpy VOC for all sectors[60]. The WRAP Oil and Gas Emissions Workgroup Phase III Inventory projected 2012 oil and gas sector VOC emissions at 127,495 tpy. Thus, the FIP is estimated to result in a 37 percent reduction in oil and gas production VOC emissions in the Uinta Basin and a 15 percent reduction in total Uinta Basin VOC emissions relative to the 2011 NEI. The proposed FIP is estimated to result in an overall 33 percent reduction in total oil and gas sector VOC emissions relative to the 2012 projection by the WRAP. The use of combustors or flares to control VOC also generates some emissions of $NO_X$ as part of the combustion process, and the EPA estimated that there would be an insignificant increase of 352 tpy of $NO_X$[61] distributed over the Uinta Basin from the use of flares and combustors, compared to 20,804 tpy oil and gas production $NO_X$ emissions and a basin-wide total of 55,745 tpy $NO_X$ emissions relative to the 2011 NEI.

Because the proposed action would result in large VOC reductions and insignificant NOx increases, we expect that the proposed FIP will reduce ambient ozone levels during the winter months. Generally, a photochemical modeling analysis is needed to determine the extent to which VOC and $NO_X$ contribute to ozone formation, and photochemical model simulations would be desirable to predict by how much this action will reduce ambient ozone levels. However, a modeling platform is not yet available that accurately simulates the observed levels of VOC, $NO_X$ and ozone in the basin during the winter months. As an alternative to photochemical modeling, we have reviewed analyses and findings from the Uinta Basin field studies in 2013 and 2014. We have also reviewed NOAA box modeling studies at the Horsepool research site[62] and a NOAA photochemical modeling study[63] for the 2013 Uinta Basin winter ozone field study.

NOAA found that the "box simulations of ozone formation chemistry based on data collected at the Horsepool study site confirm earlier analyses indicating that ozone formation at this location is sensitive to VOC reductions, i.e. VOC reductions would result in ozone reductions." The NOAA box modeling also showed that NOx reductions would lead to ozone reductions at the Horsepool site. They also noted that the box results were specific to the Horsepool site and do account for spatial variability across the basin and, therefore, do not provide an assessment of the expected impact of basin-wide VOC or $NO_X$ emission reductions. NOAA also performed photochemical modeling simulations to address spatial variability throughout the basin. The NOAA models did not accurately reproduce observed levels of VOC, $NO_X$ and ozone when they used the 2011 NEI emissions data. The NOAA models were biased low compared to observed VOC and ozone levels in the basin and was biased high compared to NOx. However, NOAA constrained the emissions inventory data using measured levels of VOC and $NO_X$ and used the constrained version of the model to evaluate ozone sensitivity to VOC and NOx. The revised NOAA photochemical modeling indicated that ozone was sensitive to VOC reductions and less sensitive to NOx reductions.

[60] See footnote 13.

[61] See discussion below on $NO_2$ impacts. Derived from EPA AP-42 Industrial Flare emissions factors.

[62] Andrews, P.M., et al., 2014, High winter ozone pollution from carbonyl photolysis in an oil and gas basin, Nature, Vol. 514, 351-354.

[63] Ahmadov, R., et al., Understanding high wintertime ozone pollution events in an oil and natural gas producing region of the western U.S.,

The emissions control measures proposed in this action are projected to result in large reductions of VOC emissions and comparatively small increases in $NO_X$ emissions associated with the use of flares or combustors to control VOC emissions. The EPA's analysis indicates that total VOC emissions will be reduced by 42,670 tpy of VOC and $NO_X$ emissions will increase by 352 tpy. Because the photochemical modeling conducted to date indicates that ozone in the Uinta Basin is more responsive to VOC, the EPA believes that the large reductions in VOC and relatively small increases in $NO_X$ emissions will result in significant reductions in ambient ozone levels in the Uinta Basin. The EPA and UDEQ will also continue to work to develop more accurate emissions inventory data and photochemical models that can be used to develop more refined emissions control strategies in the future.

b. Impacts on $NO_2$ Levels in the Uinta Basin

Combustors and flares that are used to reduce VOC emissions also emit $NO_X$ as part of the combustion process. $NO_X$ emissions include both $NO_2$ and nitric oxide (NO) which can be converted to $NO_2$ by chemical reactions. Thus, $NO_X$ emissions can cause increased ambient $NO_2$ mixing ratios. To estimate the increase in $NO_X$ emissions that would result from the proposed requirement for an estimated 3,017 oil and natural gas sources to install an enclosed combustor or utility flare to control emissions from storage tanks, glycol dehydrators, and pneumatic pumps, we first reviewed the calculations submitted by operators in the existing source registrations for 232 sources that indicated existing controls on the Indian country lands within the U&O Reservation. Most of those registrations contained calculations using the emission factor for Industrial Flares in AP-42 Chapter 13.5[64] To estimate the $NO_X$ that would be emitted as a result of required VOC combustion, we calculated the total hydrocarbon (THC) input by dividing the AP-42 THC combustion emission factor (0.14 lb/MMBtu) by the 98 percent VOC destruction efficiency (1-98 percent) proposed to be required, to come up with a THC input of 7.00 lb/MMBtu. Next, we calculated the $NO_X$ emitted from combustion of the VOCs by dividing the AP-42 $NO_X$ emissions factor (0.068 lb/MMBtu) by the THC input (7.00 lb/MMBtu) to calculate a $NO_X$ combustion: VOC input ratio of 0.010 (0.068/7.00). So for every 1 tpy VOC sent to the flare, 0.010 tpy of $NO_X$ would be emitted. To calculate the amount of VOC that would be collected for combustion under the proposed rule, we took the estimate of the total VOCs that would be reduced under the proposed rule (42,670 tpy) and subtracted the estimated VOC reductions from retrofitting pneumatic controllers (5,116 tpy) and fixing leaks (2,335 tpy), as those VOCs are not routed to a combustor and, therefore, do not produce any $NO_X$ from combustion. This resulted in an estimated 35,219 tpy VOC being combusted under the proposed rule, to which we applied the 0.010 tpy $NO_X$ emissions combustion factor to estimate that 352 tpy of $NO_X$ emitted as a result of the VOC emission control requirements in the proposed rule.

The EPA did not perform modeling because the estimate of 352 tpy total for all affected sources that we estimated would be required to combust VOC emissions under the proposed rule comes to 0.12 tpy of

[64] AP-42 Emissions Factors, Chapter 13.5 Industrial Flares, Table 13.5-1 (English Units). THC AND SOOT EMISSIONS FACTORS FOR FLARE OPERATIONS, EMISSIONS FACTOR RATING: B, Emission Factor Value 0.14 for Total hydrocarbons (THC) and 0.068 for Nitrogen oxides ($NO_X$) (emissions factor units in lb/MMBtu), available online at http://www3.epa.gov/ttnchie1/ap42/ch13/final/c13s05.pdf, accessed December 8, 2015.

$NO_X$ per source (352/3,017), which is substantially lower than the 10 tpy de minimis threshold for $NO_X$ modeling in the Federal Indian Country Minor NSR Rule[65].

c. Impacts on the NAAQS for Other Non-Ozone Related Pollutants

Potential emissions of carbon monoxide (CO) from enclosed combustors and flares used for control of VOC emissions at existing oil and natural gas sources are also expected to have an insignificant impact on the CO NAAQS because of the level and form of the CO standard in comparison to the emissions. The NAAQS for CO is set at 35,000 ppb for the 1-hour average and 9,000 ppb for the 8-hour average, not to be exceeded more than once per year. To estimate the CO that would be emitted as a result of required VOC combustion, we used the same total hydrocarbon (THC) input calculated when determining the $NO_X$ combustion emissions (7.00 lb/MMBtu). Next, we calculated the CO emitted from combustion of the VOCs by dividing the AP-42 CO emissions factor (0.37 lb/MMBtu) by the THC input (7.00 lb/MMBtu) to calculate a CO combustion: VOC input ratio of 0.053 (0.37/7.00). So for every 1 tpy VOC sent to the flare, 0.053 tpy of CO would be emitted. To calculate the amount of VOC that would be collected for combustion under the proposed rule, we took the estimate of the total VOCs that would be reduced under the proposed rule (42,670 tpy) and subtracted the estimated VOC reductions from retrofitting pneumatic controllers (5,116 tpy) and fixing leaks (2,335 tpy), as those VOCs are not routed to a combustor and, therefore, do not produce any CO from combustion. This resulted in an estimated 35,219 tpy VOC being combusted under the proposed rule, to which we applied the 0.053 tpy CO emissions combustion factor to estimate that 1,867 tpy of CO emitted as a result of the VOC emission control requirements in the proposed rule. The EPA did not perform modeling because the estimate of 1,867 tpy total for all affected sources that we estimated would be required to combust VOC emissions under the proposed rule comes to 0.62 tpy of CO per source (1,867/3,017), which is substantially lower than the 10 tpy de minimis threshold for CO modeling in the Federal Indian Country Minor NSR Rule[66].

Although not directly regulated by the proposed FIP requirements, the majority of HAP emitted by oil and natural gas production operations also meet the definition of VOC. Therefore, we estimate that 7,213 tpy HAP emissions will be reduced by the proposed requirement to control glycol dehydrator VOC emissions, 895 tpy HAP emissions will be reduced by the proposed requirement to control storage tank VOC emissions, 261 tpy HAP emissions will be reduced by the proposed requirement to control pneumatic pump VOC emissions, and 110 tpy HAP emissions will be reduced by the proposed requirement to perform fugitive emissions leak detection and repair.

## VII. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations.

[65] In the regulations for PSD permitting at 40 CFR 52.21, modeling is not required as part of the permitting process if the estimated increase in emissions is less than the minor source NSR emission threshold for a pollutant, which is 10 tpy for $NO_X$ per 40 CFR 49.153.

[66] In the regulations for PSD permitting at 40 CFR 52.21, modeling is not required as part of the permitting process if the estimated increase in emissions is less than the minor source NSR emission threshold for a pollutant, which is 10 tpy for CO per 40 CFR 49.153.

On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The Executive Order calls on each federal agency to make environmental justice a part of its mission by "identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority populations and low income populations."

The EPA defines "Environmental Justice" as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies. The EPA's goal with respect to Environmental Justice in permitting and rulemaking is to enable overburdened communities to have full and meaningful access to the permitting process and to develop permits and rules that address environmental justice issues to the greatest extent practicable under existing environmental laws. *Overburdened* is used to describe the minority, low-income, tribal and indigenous populations or communities in the United States that potentially experience disproportionate environmental harms and risks as a result of greater vulnerability to environmental hazards.

## 1. Public Participation

To promote meaningful involvement in development of the final rule, we will solicit input from potentially affected stakeholders and communities during the public comment period by posting information about the proposed rule throughout the reservation at tribal offices, community centers and publishing a notice in local newspapers. In addition, we will hold a public hearing during the public comment period and we have consulted with the Ute Tribal Business Council in multiple formal government-to-government consultations regarding the proposed FIP on December 17, 2015, and January 14, 2016. Documentation of those consultations is included in the docket for this rulemaking.

## 2. Determination

For purposes of Executive Order 12898 on environmental justice, we recognized that compliance with the National Ambient Air Quality Standards (NAAQS) is "emblematic of achieving a level of public health protection that, based on the level of protection afforded by a primary NAAQS, demonstrates that our issuance of a PSD permit for a proposed source will not have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations." *In re Shell Gulf of Mexico, Inc. & Shell Offshore, Inc.*, 15 E.A.D., slip op. at 74 (EAB 2010). This is because the NAAQS are health-based standards, designed to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly and asthmatics. Although taken from the context of issuance of a PSD permit, this logic applies with equal force to our issuance of a Federal Implementation Plan under the CAA.

We determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority, low income and indigenous populations on the Indian country lands within the U&O Reservation and surrounding areas because it seeks to address compliance with the NAAQS and provides environmental protection for all affected populations, including minority, low income and indigenous populations.

### 3. Demographics

Additionally, the Agency has reviewed this rule to determine if there is an overrepresentation of minority, low income, or indigenous populations near the affected sources[67] such that they may currently face disproportionate risks from pollutants that could be mitigated by this rulemaking. This analysis only gives some indication of the prevalence of sub-populations that may be exposed to air pollution from the sources affected by this rulemaking; it does not identify the demographic characteristics of the most highly affected individuals or communities, nor does it quantify the level of risk faced by those individuals or communities.

We reviewed the demographics of the potentially affected population for the prevalence of minority, low income, or indigenous populations. The EPA consulted the U.S. Bureau of the Census, American QuickFacts[68] and EJSCREEN[69] for demographic and socioeconomic data. Table 20 provides information from the 2010 U.S. Census for census blocks within the exterior boundary of the U&O Reservation[70] as defined by the U.S. Census Bureau.

Table 20 – Demographic and Socioeconomic Information for Census Blocks within Exterior Boundaries of U&O Reservation

| County | Number of Affected Census Blocks | Total Population | Minority Population | American Indian Population | Hispanic Population | Persons Under 18 | Persons Over 65 |
|---|---|---|---|---|---|---|---|
| Carbon | 16 | 0 | 0 | 0 | 0 | 0 | 0 |
| Duchesne | 2,523 | 18,605 | 2,396 | 842 | 1,117 | 6,309 | 1,982 |
| Emery | 4 | 0 | 0 | 0 | 0 | 0 | 0 |
| Grand | 48 | 0 | 0 | 0 | 0 | 0 | 0 |

[67] Affected sources and equipment based on existing minor source registrations submitted by operators under the Federal Minor New Source Review program in Indian Country at 40 CFR Part 49.

[68] QuickFacts tables are summary profiles showing frequently requested data items from various Census Bureau programs. Profiles are available for the nation, states, counties and places. http://quickfacts.census.gov/qfd/states/49/49013.html

[69] EJSCREEN is EPA's environmental justice mapping and screening tool that provides nationally consistent datasets and approach for combining environmental and demographic indicators. The information provided can be considered in a wide range of program contexts and will help meet E.O. 12898's call for EPA to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of our programs, policies and activities. All of the EJSCREEN indicators are publicly-available data. It also includes publicly available demographic data from the U.S. Census Bureau, American Community Survey (ACS) 2008-2012. http://www2.epa.gov/ejscreen

[70] U.S. Census Bureau 2009 TIGER shape files. EPA makes no claim regarding the accuracy or precision of these data. Questions concerning the data should be referred to the source agency. This product does not necessarily represent EPA's position on any Indian Country boundaries or the jurisdictional status of any specific location.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Summit | 2 | 0 | 0 | 0 | 0 | 0 | 0 |
| Uintah | 1,458 | 5,753 | 2,500 | 2,109 | 270 | 1,971 | 536 |
| Utah | 21 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wasatch | 467 | 11 | 3 | 0 | 0 | 2 | 3 |
| Total | 4,539 | 24,369 | 4,899 | 2,951 | 1,387 | 8,282 | 2,521 |

The reservation encompasses approximately 6,823 square miles with a population of 24,369. Seventy five percent of the census blocks are unoccupied. Twenty percent of the persons residing within the exterior boundary of the reservation are minority with 12 percent of the population American Indian.

Certain demographic and socioeconomic data for residents of the U&O Reservation were missing from EJSCREEN and the U.S. Bureau of the Census, including languages other than English spoken at home educational status and economic status. Seventy-six percent of the population in Duchesne County resides within the exterior boundaries of the Reservation, therefore, the EPA reviewed demographic and socioeconomic data from the American QuickFacts for Duchesne County, the State of Utah, and the United States in order to characterize the missing information for the general area within the U&O Reservation.

Table 21 summarizes the percent of the total population that has a given demographic or socioeconomic characteristic. The same information is presented graphically in the following bar chart (see Figure 3):

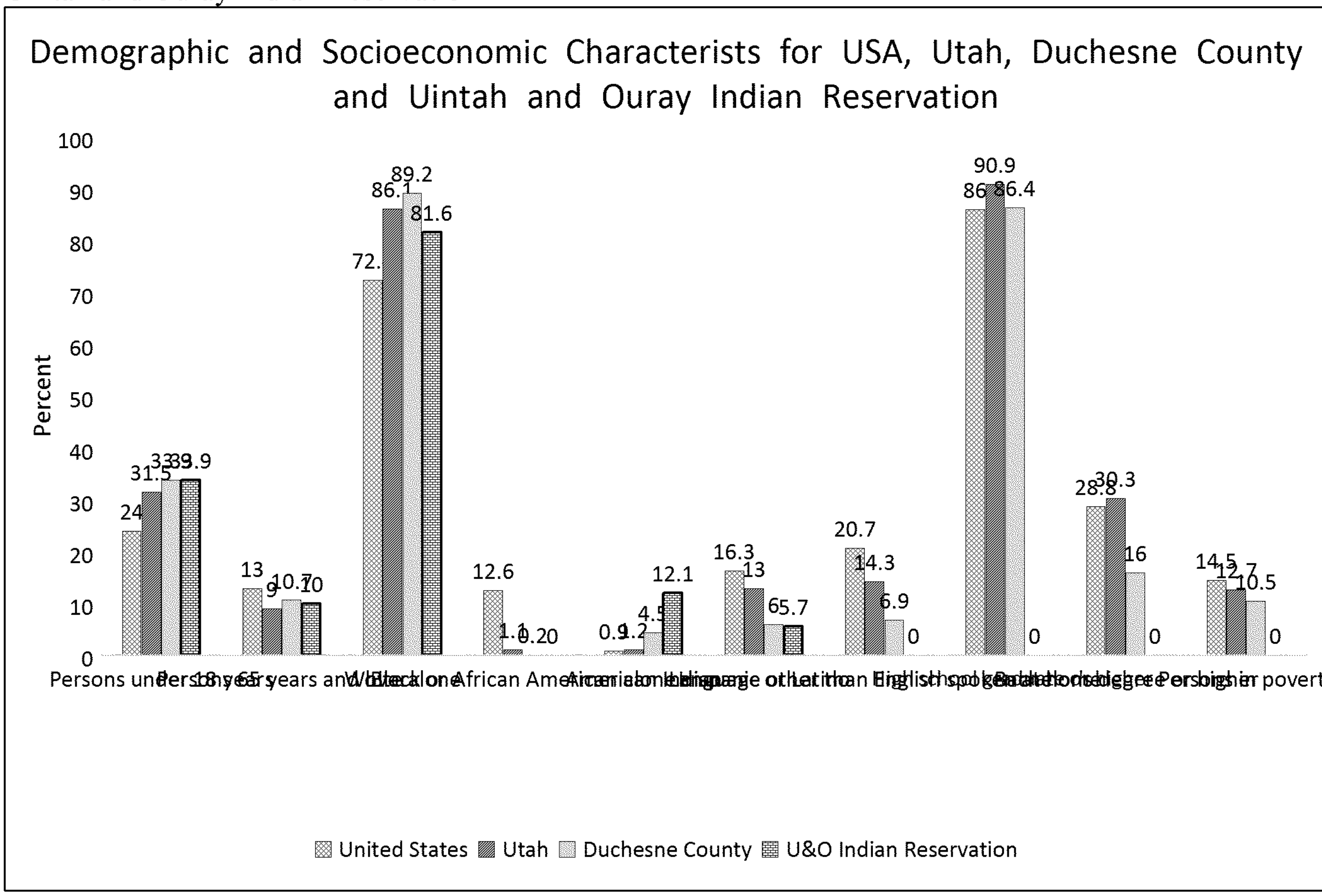
Table 21 – Distribution of Population Meeting Certain Demographic or Socioeconomic Characteristics

| Demographic and Socioeconomic Characteristic* | Uintah and Ouray Indian Reservation | Duchesne County | Utah | United States |
|---|---|---|---|---|
| Population | 24,369 | 1,8605 | 2,763,885 | 308,745,538 |
| Persons under 18 years | 34 | 34 | 32 | 24 |
| Persons 65 years and over | 10 | 11 | 9 | 13 |
| White alone | 82 | 87.1 | 86 | 72 |
| American Indian and Alaska Native alone | 12 | 5 | 1 | 1 |
| Hispanic or Latino | 6 | 6 | 13 | 16 |
| Language other than English spoken at home, persons age 5 years+, 2009-2013 | | 7 | 14 | 21 |
| High school graduate or higher, age 25 years+, 2009-2013 | | 86 | 91 | 86 |
| Bachelor's degree or higher, age 25 years+, 2009-2013 | | 16 | 30 | 29 |
| Persons in poverty | | 11 | 13 | 15 |
| Median household income (2013 dollars), 2009-2013 | | 57,683 | 58,821 | 53,046 |
| Per capita income in past 12 months (2013 dollars), 2009-2013 | | 23,411 | 23873 | 28155 |

| | | | | |
|---|---|---|---|---|
| Population per square mile | 4 | 6 | 34 | 87 |
| Land area in square miles | 6,824 | 3241 | 82,170 | 3,531,905 |

*U.S. Census 2010 percent of population unless noted otherwise
Racial and ethnic categories overlap and cannot be summed.
The "minorities" population is the overall population minus the white population.
The Census Bureau defines "Hispanic or Latino" as an ethnicity rather than as a racial category, Hispanics or Latinos may belong to any race.

Figure 3 - Demographic and Socioeconomic Characteristics for USA, Utah, Duchesne County and Uintah and Ouray Indian Reservation




The general characteristics indicate a slightly younger population than Utah and the United States with a higher population of American Indians and fewer hispanic/latino persons. English is the predominate language spoken at home and the high school education level is in line with the United States as a whole. Economically, persons on the reservations are experiencing poverty at levels similar to residents of Utah and the United States.

## VIII. Conclusion

In light of the concerns about air quality on Indian country lands within the U&O Reservation due to oil and natural gas activity and the inconsistencies between UDEQ and the EPA regulation of oil and natural gas activity in the Uinta Basin, the EPA believes that it is appropriate to establish the air quality rule that is proposed today. Under the proposed rule, we will require the oil and natural gas production industry on the Indian country lands within the U&O Reservation to meet standards equivalent to those imposed by the UDEQ rules for areas outside of the Indian country lands within the U&O Reservation and elsewhere in the Uinta Basin. The proposed rule will provide air quality protection for residents on the Indian country lands within the U&O Reservation that is equal to the protection provided for residents in the other portions of the Uinta Basin by way of making VOC emissions control requirements for existing oil and natural gas sources consistent across jurisdictional borders, thereby avoiding potentially disproportionately high and adverse human health or environmental effects on minority, low-income, tribal and indigenous populations from oil and natural gas production operations. Further, as explained previously in this document, though we were unable to quantify it, we expect that the reduction in VOC emissions to the atmosphere will result in improvements in air quality and reduce health and welfare effects associated with exposure to ozone, while the small $NO_x$ emissions increases are not expected to have a meaningful impact on ozone formation.

This rule would regulate activities, pollutants and sources by supplementing the existing federal regulatory programs such as the PSD, Minor NSR, Title V, NSPS and NESHAP programs. This proposed rule would provide additional regulatory tools for us to use in implementing the CAA on the Indian country lands within the U&O Reservation. We have adequate enforcement authority under Section 113 of the CAA to ensure compliance with the requirements that are proposed.

Regulating these sources is appropriate not only in order to protect air quality from the potential for significant deterioration caused by the release of VOC, but also to ensure equal incentive for operators to develop the mineral resource on Indian country versus state land. VOC is regulated indirectly by NAAQS as a precursor to ozone formation under section 109 of the CAA. The rule proposed today would control emissions of VOC to the atmosphere as appropriate for the purpose of maintaining or attaining the NAAQS for ozone.

We believe that this rule is appropriate because it establishes federally enforceable requirements to control VOC emissions from existing oil and natural gas production equipment equivalent to the requirements imposed by the UDEQ, which will provide owners and operators with consistent regulatory certainty across jurisdictional boundaries. Thus, the FIP equalizes the playing field between the UDEQ jurisdiction and our jurisdiction on the Indian country lands within the U&O Reservation.